OPTIMIZATION OF VERTICAL PLACEMENT OF HORIZONTAL WELLS IN MATURE CARBONATE RESERVOIRS

BY

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DEDICATION

I would like to dedicate this work to my parents, wife and daughter.

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I would like to express my deepest appreciation to Dr. Muhammad Al-Marhoun for his continuous guidance, advice and motivation throughout the course of the study. Furthermore, I would like to thank my committee members, Dr. Hasan Y. Al-Yousef, Dr. Abdullah S. Al-Sultan, Dr. Darryl B. Fischbuch and Dr. Dr. Abdulaziz Al-Majed for their support, help and advice.

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THESIS ABSTRACT

Full Name : Ali Hassan Al-Julaih

Thesis Title : OPTIMIZATION OF VERTICAL PLACEMENT AND RESERVOIR CONTACT OF HORIZONTAL WELLS IN MATURE CARBONATE RESERVOIRS

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The increasing oil demand makes it imperative to maximize recoveries from the existing fields. Recoveries can be maximized through prudent reservoir management techniques and implementation of fit-for-purpose technologies. Implementing modern monitoring program in an oil field helped in the identification of un-swept zones. A recent study has found that the upper most zones of large carbonate reservoir remain largely un-swept even in mature areas whereas the lower zones are mostly swept. This created an opportunity to produce the upper zones through dedicated horizontal producers. The question this thesis tries to answer is whether there is an optimum vertical placement and length of horizontal wells to effectively produce such thin un-swept oil zones. The study was carried out utilizing a full-field simulation model. A typical oil carbonate reservoir was selected to investigate well performance based on various scenarios taken into consideration several factors including the history of the field and its geology. Instead of drilling new wells and in order to reduce development cost, four existing vertical wells were selected as potential side-tracking candidates after a thorough screening. In the history matching process, the historical performance of the selected wells and their off-sets was effectively reproduced. When predictions were performed, the model showed

that placing horizontal wells in this zone results in a significant added recovery. It also showed that this recovery can be maximized by placing the laterals in the top layer. It was also illustrated that, in general, the recovery can be increased by extending the length of the reservoir contact. Moreover, the quality of the zone in which the well in placed as well as the existence of natural fractures play a major role in well performance.

ملخص الرسالة

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عنوان الرسالة: ايجاد الموقع العمودي والطول الامثل للإبار الافقية في المكامن الكربونية

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تزايد الطلب على النفط يجعل من الضروري استخراج أقصى قدر من احتياطاته من الحقول القائمة. يمكن زيادة هذه الاحتياطيات من خلال اتباع استراتيجيات حكيمة لإدارة المكامن وأيضا من خلال تطبيق التقنيات المناسبة. إن تطبيق استراتيجيات رصد حديثة ساعد كثيرا في اكتشاف اجزاء تحتوي على كميات كبيرة من النفط. وجدت هذه الدراسة أن الجزء العلوي من المكمن في معظم المناطق لا زال يحتوي على كميات كبيرة من النفط على الرغم من انتاج المكمن لسنوات طويلة. وهذه فرصة لإنتاج هذه المناطق بواسطه ابار انتاج افقية. السؤال الذي يحاول هذا البحث الإجابة عنه هو ما إذا كان هناك موقع راسي و طول امثل لهذه الابار الأفقية يسهم في زياده انتاجها. أجريت الدراسة باستخدام نموذج محاكاة بدلا من حفر ابار جديدة و بغيه لخفض تكاليف التطوير تم اختيار اربعه ابار رأسية قائمة عن طريق استخدام نموذج المحاكاة لتقويم نتائج تحويلها لأبار افقيه موضوعة في الجزء العلوي من المكمن وعندما درست الإستشرافات المستقبلية لأداء هذه الابار ، أظهرت النتائج ان تحويل الابار الى افقية ومنتجة من الجزء العلوي من المكمن يسهم وبشكل كبير في زيادة الاحتياطيات القابلة للإنتاج. كذلك اظهرت النتائج ان وضع هذه الابار افقيا في الطبقة العليا للجزء العلوي من الممكن يسهم في زيادة انتاجها. كما انه اتضح بصفة عامة، إمكانية زيادة انتاج هذه الابار من خلال زيادة طولها الافقي. كذلك بينت الدراسة ان التصدعات الطبيعية تؤثر بشكل كبير على اداء هذه الابار.

CHAPTER 1

INTRODUCTION

The demand for energy has been increasing and it is expected to continue to grow. Oil has a significant share in the global energy mix. Since very limited new discoveries are expected, existing fields will play a major role in meeting the energy demand. Therefore, it is imperative to maximize the recoveries from existing fields. Development strategies, reservoir management techniques and implementation of fit-for-purpose technologies play a crucial role in fulfilling this objective. A technological break-through that has helped the industry to maximize recovery is horizontal wells, especially when the targeted zone/reservoir has only a thin oil column. In many cases, the development of such thin oil zones is economical only with horizontal wells. Optimizing the vertical placement and the length of the reservoir contact of the horizontal wells could greatly improve their effectiveness in depleting a targeted zone.

1.1 The World Energy Demand

In recent years, demand for energy has been increasing rapidly. This demand is expected to grow as the World Energy Outlook shows that energy demand could rise by 53% between 2013 and 2030. Currently, more than 85% of world energy consumption comes from fossil fuels. They continue to be the main source of energy worldwide, though renewables are growing rapidly. By 2035, fossil fuels combined share of the global energy mix is estimated to be 75%. The base case estimate by the International Energy Agency (IEA) shows that world oil production in 2040 will exceed the 2012 level by 23 million barrels per day reaching 112 million barrels per day, Fig.1.1. By then, the world will consume over 1.06 B STB of oil, which equates to around 72% of the world current reserves [1].

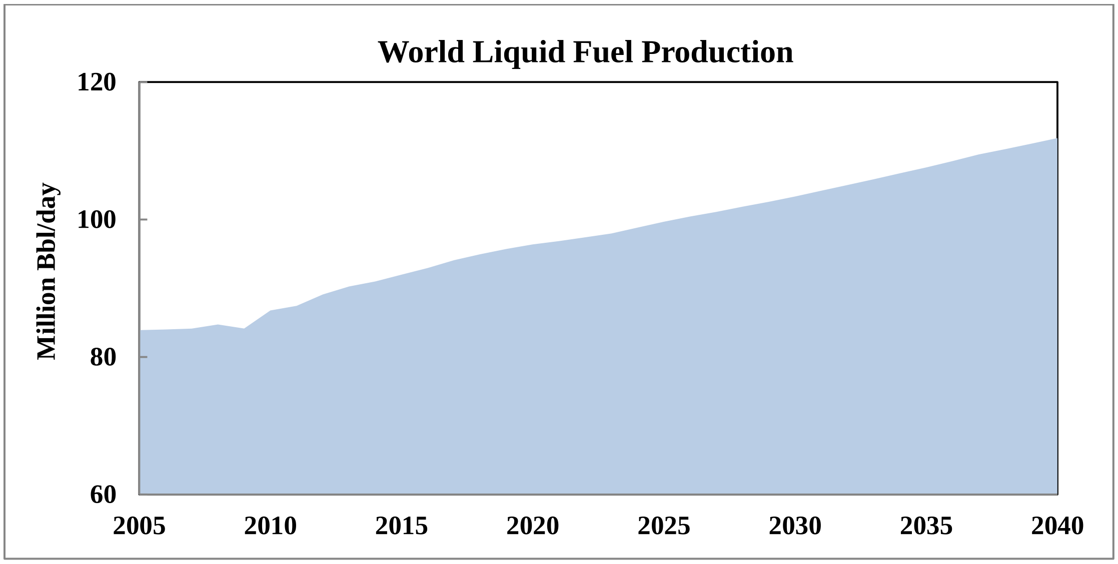

Figure 1.1: World Liquid Fuel Production

Since there is a decline in the number of oil discoveries during the last decades, the world is counting on the existing fields to play a key role in meeting the energy demand for long years to come. Therefore, to sustain global demand of energy resources, it is vital to improve the current conventional reserves. However, most of the conventional oil reserves remaining today are limited to fields that were discovered more than 30 years ago or in other words, mature fields. Therefore, increasing the recovery factors from mature fields is critical to fulfill the growing energy demand.

1.2 Carbonate Reservoirs

More than 60% of the world's current reserves are located in carbonate reservoirs. About 70% of the proven conventional reserves in the Middle East, which accounts for about

62% of the world reverses, are located in carbonate reservoirs. Average recovery factors in carbonate reservoirs are generally lower than those that can be achieved in clastic reservoirs mainly due to their greater level of heterogeneity.

A study that looked at 250 mature carbonate reservoirs showed that for the data gathered, carbonate oil reservoirs have an average recovery factor of 36%, Fig. 1.2. The study suggested that a higher recovery factor reflects good reservoir management practices and successful application of EOR techniques [2].

Development strategies, reservoir management techniques and the implementation of fit-for-purpose technologies play a crucial role in maximizing the expected ultimate recoveries.

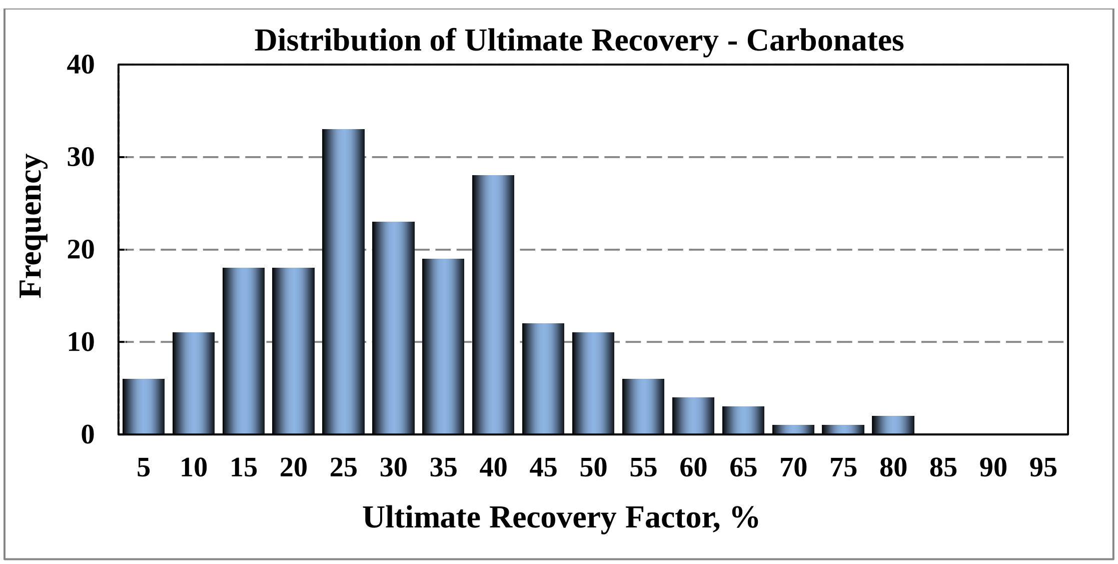

Figure 1.2: Distribution of Ultimate Recovery Factor – Carbonates Reservoirs

1.3 Recovery Factor

The recovery factor (RF) is the product of a combination of three efficiency factors as given by the following generalized expression:

$$RF = E_D\,E_A\,E_V \qquad (1.1)$$

Where:

RF = overall recovery factor

E_D = displacement efficiency

E_A = areal sweep efficiency

E_V = vertical sweep efficiency

The displacement efficiency E_D is the fraction of mobile oil that has been displaced from a zone at any given time or pore volume injected. Because an immiscible gas injection or water-flood will always leave behind some residual oil, E_D is always be less than 1.0.

The areal sweep efficiency E_A is the fractional area of the reservoir that is swept by the displacing fluid. The major factors determining areal sweep are: mobility ratio M, flood pattern and cumulative water injected W_{inj}. It increases progressively with injection from zero at the start of the flood until breakthrough occurs, after which it continues to increase at a slower rate. Proper management of pressure distribution and proper injection-production pattern selection improves areal sweep.

The vertical sweep efficiency E_V is the fraction of the vertical section of the pay zone that is contacted by injected fluids. The vertical sweep efficiency is primarily a function of:

vertical heterogeneity, degree of gravity segregation, fluid mobilities, and total injection volume. In the case of non-uniform permeabilities within the reservoir, injected fluids will have a tendency to move through the reservoir with an irregular front. In the more permeable zone/s, the injected water will travel faster than in the less permeable zone/s[3].

1.4 Horizontal wells

It has been well established that the effective development of challenging reservoirs is best achieved with horizontal wells due to exposing wellbore to maximum reservoir contact and drainage area. Through horizontal wells, additional recovery, higher production rate, lower gas/water production, longer well life and lower until development cost can be achieved. In most cases, development of thin oil zones is economically feasible only through horizontal wells, Fig. 1.3.

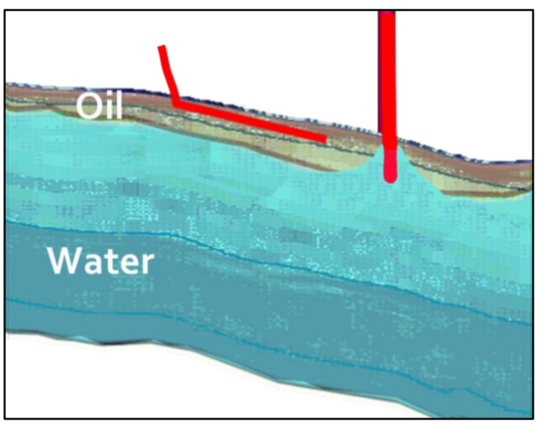

Figure1.3: Advantages of horizontal wells

1.5 Objective

The objective of the study is to utilize the full-field simulation model in order to optimize the vertical placement and the length of the reservoir contact the of horizontal wells to effectively produce a thin un-swept oil zone that is located at the top of a thick, partially swept carbonate reservoir in the Middle East.

The study utilizes actual geological and engineering data. In order to reduce development cost, the study was carried out on dead/marginal vertical wells that can be side-tracked as horizontal wells instead of drilling new wells.

CHAPTER 2

LITERATURE REVIEW

The literature contains a number of case studies illustrating the benefits of developing thin oil reservoirs using horizontal wells. The benefits of using horizontal instead of vertical wells are greater when the oil zone is thin and underlying a gas cap and/or overlying a strong aquifer. In many cases, the development of such thin oil zones is economical only with horizontal wells. The optimum placement and the length of the reservoir contact of these wells have been discussed in several papers. In many of these papers, there is a strong emphasis on the importance of utilizing reservoir simulation to guide and optimize the development plans of thin oil column zones.

In 1991, a paper was published discussing the first long-term horizontal-well test in Troll thin oil zone which was conducted as pilot in order to prove thin oil column zone reserves. The field is located below 300 m of water offshore Norway.

The sandstone reservoir contains 0-26 m thick oil rim sandwiched between a large gas cap and active water aquifer. The oil zone is located in high-quality sandstone that has a permeability ranging between 3 to 10 D. Developing the field by vertical wells was considered economically marginal due to severe gas coning resulting in sharply decreasing oil rates. Tests were conducted in six vertical exploration wells resulted in oil rates of 600-1200 Stock-tank m^3/d and gas break-through occurrence within 2 to 3 days.

Since horizontal wells were known to improve productivity and reduce water/gas coning problems, developing this thin oil zone through horizontal wells was considered. However, because of the 300-m water depth, highly unconsolidated sand, and thin oil column, the development was considered as a high-risk project. Therefore, prior to piloting a well, reservoir simulation study was carried out. The full-field simulations showed that the use of 500-m horizontal wells will result in gain in the instantaneous oil rate and cumulative production by three to four times compared to vertical wells and thereby reducing the number of wells needed by a factor of four. Since the cost of a horizontal well only is 1.2 to 1.5 times the cost of a vertical well, these results clearly indicated a significant potential for development through horizontal wells.

A pilot of a 500-m horizontal well was drilled with placement at 4 m above the WOC. The production performance of the well confirmed that the initial rate of a horizontal well is at least four times higher than that expected from a vertical well in the same area. The time to gas break-through was also longer than expected. The results of the long-term test in terms of cumulative oil confirmed the existence of significant oil potential and the feasibility of recovering the Troll thin oil zones[4].

In 1993, a paper was published focusing on efforts to evaluate and justify drilling a pilot horizontal well in a 33-ft oil zone located in South Sumatra, Indonesia. The zone is located between a gas cap and water aquifer and has an average porosity of 24% and average permeability of 230 mD.

Due to its limited thickness, the few vertical wells completed in this zone produced at low oil rates and yielded marginal to non-economic results because of severe water and gas coning. Even though the cost of drilling a horizontal well is higher than drilling a vertical well, horizontal wells provided hope for coning mitigation and improving profitability.

To be able to select the optimum choice to develop the field, an economic comparison between the two development alternatives: vertical vs. horizontal drilling was conducted. To be able to conduct the comparison, a simple, three-dimensional, three-phase simulation model was constructed.

Selection of the optimum alternative was based on the maximum present value profit with an acceptable rate of return. The model showed that horizontal well development is more economically attractive and will recover twice the amount of oil recovered by vertical wells. Moreover, the optimum placement of the horizontal wells was found to be 25 ft below the GOC. When drilled and produced, production performance was consistent with the simulation results[5].

In 1993, a paper was published discussing the Airlie Project, located in the north-west coast of Western Australia. The reservoir consists of thin oil column ranging between 7 to 15 m gross thickness. Reservoir permeability varies from less than 0.01 mD laminated silt and shale to greater than 10,000 mD in clean sandstone but typically between 500-1000 mD. The effective porosity ranges from 15 to 28%. In this project, reservoir simulation was instrumental in the optimization processes of the horizontal well placement. It was concluded from simulation studies and the appraisal drilling that horizontal wells drilled in such thin oil column reservoir should be placed as high in the remaining oil column as possible. However, such strategy may result in temporary high gas production[6].

A paper was published in 1993 about the development of Shuaiba reservoir in the SaihRawl Field, Central Oman. The reservoir contains under-saturated oil in a thin oil column of less than 25 m. The field was originally developed with vertical wells. The performance of these vertical wells was discouraging due to rapid coning of the bottom water. Later, a study was conducted to assess developing the field through horizontal wells. A simulation study was carried out to assess the impact of different parameters on the development. These parameters included: the effect of the oil column height, well spacing and reservoir quality. In all of the prediction runs, the horizontal wells were located 2 m from the top of the reservoir. Prediction runs were made at three different oil column heights (25 m, 20 m, and 15 m). It was observed that cumulative oil production reduces significantly at lower oil heights[7].

In 1996, a paper was published highlighting a study that was conducted to determine the best development scheme to recover oil and gas from two oil rim reservoirs located off shore Abu Dhabi utilizing horizontal wells. These two oil rims are overlain by large gas caps. The upper reservoir a 30-ft thick limestone that has a porosity ranging between 10 to 15% and a permeability ranging from 280 to 600 mD. The lower reservoir is 175 ft thick and composed of sequence of clean limestone with minor dolomites and dolomitic limestone. It has a porosity ranging between 7 to 15% and a permeability ranging from 15 to 30 mD.

Historically, two vertical wells were completed in the upper oil rim and two other wells were completed in the lower rim. The two completed in the upper rim were re-completed in other horizons after short production while the two completed in the lower rim were closed due to water break-through. The amount of oil that could be produced from the two rims was very limited.

An analytical approach was tried to optimize the placement and the length of the horizontal section. The optimum placement was defined as the well elevation in the vertical plane at which both water and gas simultaneously break-through. In the study, horizontal wells with 2500 ft and 4000 ft of reservoir contact were assumed. The initial rate was assumed to be 1500 STB/d. The study indicated that the optimum placement is the midpoint between the GOC and the WOC. Moreover, it showed that the performance of the 4000 ft horizontal well is far better than the 2500 ft well.

After conducting the study, it was recommended to drill a pilot to assess the effectiveness of horizontal drilling and to construct a sector model in order to optimize the results of the analytical approach, predict well performance and estimate the number of wells needed for full-field development. The model showed also that a horizontal well with 2500 ft reservoir contact can produce twice as much as a vertical well completed in the same layer. This ratio goes up to four times when compared to horizontal well with 4000 ft reservoir contact. It also showed that the optimum placement of the horizontal section is mid-way between the fluids contacts.

In order to minimize the uncertainties associated with determination of the fluids contacts, a pilot vertical hole was drilled before drilling the horizontal section.

Comprehensive formation evaluation was planned in this vertical hole with objectives to better assess the current fluid saturation in the area, identify the current fluid contacts and cut cores for detailed core analysis.

Logs that were run in the vertical pilot showed severe water movement into the part where the horizontal lateral was planned. As a result, the vertical placement of the planned lateral was modified to be completed at a higher layer. A 3400 ft lateral was drilled around 25 ft below the GOC. When placed on production and tested, the well proved to be successful in terms of high production rate, minimum pressure drawdown and relatively low GOR[8].

In 1999, a paper was published discussing a case study about the development of a thin oil column field under water drive, Serang Field, Indonesia. The thin oil column is located in a good permeability reservoir that is sandwiched between gas cap and water leg. Reservoir modeling was utilized to identify fluid contacts, select a completion placement (well placement, length, distance to fluids contacts, optimal rate) which is essential to predict the performance of the planned wells. The model suggested that locating wells too close to the GOC could result in reducing oil recovery due to the possibility of premature gas cap blowdown. Improved oil recovery was observed when wells are completed in the top half of the oil column, towards the middle. The disadvantage of a lower completion towards the WOC is higher water production. Moreover, the smaller the relative size of the gas cap, the smaller loss of oil reserves due to gas cap blowdown. The model also showed that the longer the well the better is performs. The optimal length was found to be around 800 ft to 1000 ft. Based on the results of the reservoir model in addition to actual field data, the development of this thin oil column reservoir through horizontal was optimized. When applied, successful results were proved with several wells in the field [9].

In 2001, a paper was published presenting a case study that highlights the lessons learned from exploiting and managing a sandstone reservoir with less than 20 ft of oil column and the future development plans using horizontal wells. After a long-term continuous production, the originally thick oil columns in Attaka Field, Indonesia, became thinner. Yet, the remaining oil zone of less than 20 ft which sandwiched between gas cap and bottom/edge aquifer still contains significant reserves.

In order to plan the completion strategy, a reservoir simulation model was utilized. The model was used to optimize the development strategy including well placement, length, distance to fluid contacts and rate. Results showed that placing the well toward the middle of the oil zone tends to give better recovery. The effect of well length was also evaluated. The optimal length was found to be 600 ft. The paper suggested that even though the longer the well the better it performs, higher geological and drilling risks are associated with drilling extremely long wells as they may cross unexpected faults or encounter mechanical problems while running long screens. The paper also highlighted that since permeability is high and with the existent of strong gas cap and water support, pressure drop in the reservoir and along the well is relatively small and therefore, a very long well may not contribute a lot more than it should.

The paper also highlighted that in order to reduce the development risk, it is important to perform continuous reservoir surveillance to assess current fluids contacts. Data collected through surveillance should be utilized to update the reservoir model[10].

In 2003, another paper was published discussing the development of thin oil column reservoirs. The field in this case is Platong Field located in the Gulf of Thailand. The 37B sand in the Platong Field has a 30 ft oil column, a small gas cap, and large underlying aquifer. A simulation model was constructed to evaluate different horizontal well parameters that affect oil recovery including well placement, the length of the horizontal well and the size of the production tubing. The study showed that for a small gas cap relative to the oil volume, the oil recovery increases as the well was placed closer to the gas cap. In the case of 37B Sand, the highest oil recovery can be achieved by placing the well in the gas cap because of the existence of a strong water drive. The model was used also to optimize the length of the well. The optimal length was found to be 1350 ft as the incremental oil recovery becomes smaller as well length increases above 1350 ft [11].

A paper written in 2003 illustrates the reservoir simulation work that was conducted to determine the best strategy to deplete the Amherstia/Immorelle 22 sand located in Trinidad and Tobago. The reservoir consists of an oil rim with varying thickness of 31 to 46 ft. The overlying gas cap has a relativity huge volume. A full field model was constructed. The model was essential to study multiple well interference effects and well location sensitivities in order to optimize the development plan. One of the main features of the model is the local grid refinements over areas where existing and planned wells are located to study near wellbore effect. Number of sensitivities were conducted to determine the optimum depletion strategy. These included distance below GOC, timing of well completion, initial rate, lateral length, tubing size and aquifer size. To study the sensitivity of distance to the GOC, the results of locating a well 20 ft, 10ft, and 5ft below the GOC were compared. Locating the well at 5 ft below the GOC resulted in the highest recovery. Moreover, different well lengths were compared. An increase in recovery was seen by larger tubing size and longer lateral length. The incremental production gained by increasing both was much greater than the increase seen when only the lateral length is increased which may suggest that the wells are limited by the tubing size [12].

In 2005, a paper was published describing the development of the Mahogany field in Trinidad and Tobago. The zone of interest is a sandstone reservoir called 21 sand containing a thin oil rim. It has porosity ranging from 24 to 26 % and permeability ranging from 300 mD to 1 D. The 21 sand is divided into two compartments. The first compartment has overall thickness of 470 ft, of which 82ft is gas leg, 74 ft is oil leg and 314 ft is the water aquifer. The second compartment has a gas leg of 341 ft, 72 ft of oil leg and 189 ft of water leg. The development team decided to place the horizontal oil wells one third the way from the gas oil contact rather than placing them in the center of the oil leg. The strategy led to more oil production before water breakthrough. At the same time, the wells didn't suffer premature gas breakthrough[13].

The literature shows that the vertical placement of horizontal wells in thin oil zones depends on several factors. These factors include oil zone thickness, size of gas cap, strength of aquifer, and the rock quality of the oil zone. It also illustrates the added value of utilizing the simulation models in order to optimize the length of these wells.

CHAPTER 3

RESERVOIR OVERVIEW

The studied reservoir contains light crude oil that has mid. thirties API gravity. The area of interest in the field has a long production history of more than 50 years. It was initially produced under natural depletion drive. Full pressure maintenance was initiated in the 80s by peripheral water injection. Development and infill drilling are still underway and tapping oil reserves across the field, including areas behind the flood front.

The reservoir consists of a thick carbonate anticline capped by a continuous anhydrite (evaporite) seal. It is part of a Jurassic Formation that consists of four geographically extensive carbonate-evaporite cycles. The reservoir consists of several (at least four) major upward-shoaling cycles that were initiated in deeper sub-tidal water and shoaled to near sea-level. These up-ward shoaling cycles comprise a variety of skeletal grainstones and packstones with ooid grainstones.

3.1 The Depositional Environment

The depositional environment in which this reservoir was created consists of a lower slope marine (low energy) for the lower two zones (3&4), shoal and upper slope marine (high energy) for Zone-2, and tidal flat and lagoon (low to medium energy) for Zone 1, Fig. 3.1. The high energy environment has produced limestone facies dominated by oolites and grain-stones. The dominant depositional environment for the better quality rock was the higher energy, upper slope platform. Oolites represent the highest energy depositional environment and produced the greatest porosity/permeability grain-stones.

Calcareous sands are most permeable where lime mud does not fill the intergranular space. Poorer quality reservoir rock has a larger proportion of lime mud matrix.

On the other hand, the lower energy environment has produced varying combinations of wackestones, packstones and mudstones. Zone-1 facies consist of dolomitized grainstones and wackestones, which can occur as single or dual porosity lobes and can be laterally discontinuous. Nodular anhydrite micro-stringers are frequently found between porosity lobes and often between Zones 1 and 2.

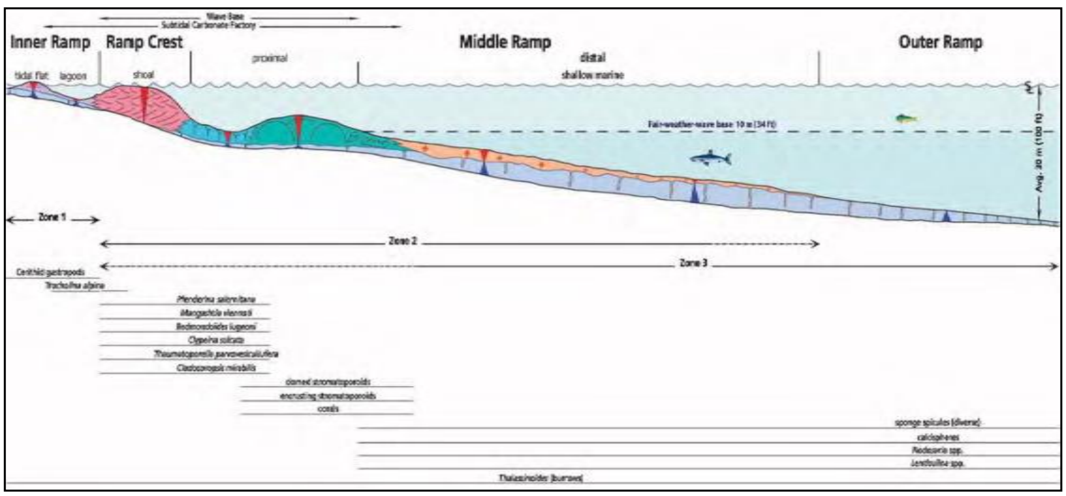

Figure 3.1: Reservoir Depositional Environment

3.2 The Targeted Zone

The targeted zone, Zone-1, is a thin heterogeneous interval located at the top the reservoir. It represents a transition zone between the overlying nonporous anhydrites and the underlying high-quality zone that consists of massive, relatively homogeneous, highly porous and permeable rock. Zone-1 thickness varies from extremely thin to about 20 ft, Fig. 3.2.

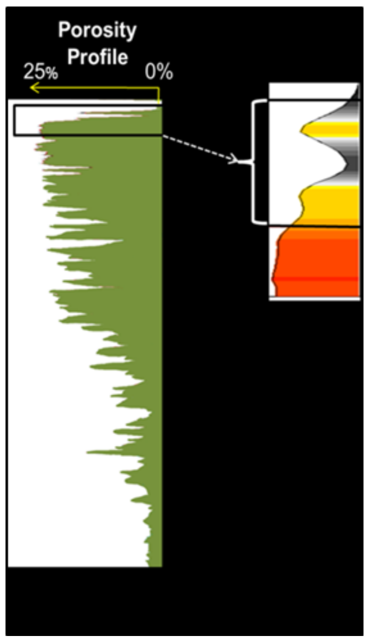

Figure 3.2: Typical Open-hole log showing the whole reservoir and the targeted zone

The properties of Zone-1 vary throughout the field. Heterogeneity is present with lateral facies changes. The zone may consist of single or multiple lobes. In the first example (Fig. 3.3, Well-A), Zone-1 is a 3 ft single lobe with poor rock quality. On the other hand, the second example (Fig. 3.3, Well-B) shows a 10-ft thick Zone-1 consisting of a single lobe with much better rock quality than Well-A. The third example (Fig. 3.3, Well-C) shows a 13 ft thick Zone-1 consisting of two lobes with good porosity and separated by a tight layer in between them.

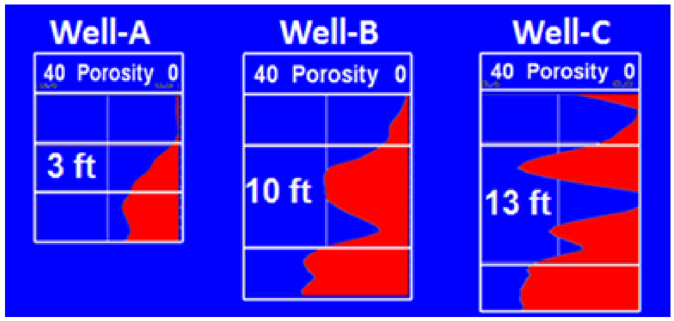

Figure 3.3: Variation of Zone-1 properties throughout the field

3.3 Geological Model Development

The newly developed geological model consists of 8 zones with a total of 255 geologic layers. It employs an areal cell size of 125 meters by 125 meters. The first step in developing a comprehensive geological model of Zone-1 was the well by well analysis of formation tops which resulted in producing a Zone-1 gross thickness iso-pach map.

A porosity-thickness (ΣΦh) map was later generated, part of which is shown in Fig. 3.4. The map was utilized to identify the most promising Zone-1 sidetrack and new well candidates. Maximum ΣΦh is designated by blue and grading to lower values through green to yellow. The map was used as the primary basis for selecting Zone-1 sidetrack and new well candidates in the field.

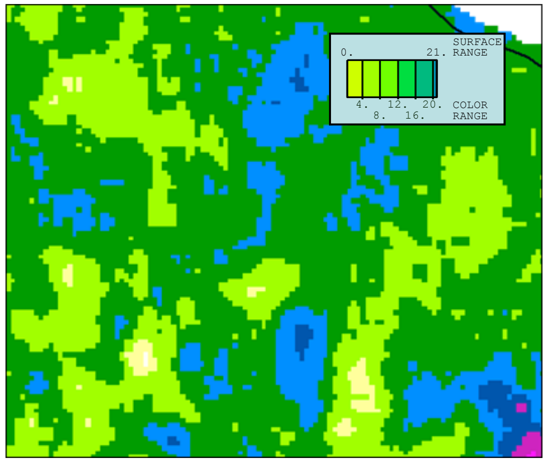

Figure 3.4: Part of Zone 1 Φh map

3.4 Assessment of Remaining Oil

The comprehensive reservoir monitoring program that has been implemented in the field is meant for monitoring sweep progression, quantifying remaining oil saturation, and determining remaining oil column in the entire field with emphasis on mature areas behind the flood front. The program consists of running different types of logs on existing wells and also drilling new dedicated evaluation wells in selective locations.

The results of the program showed uniform sweep and flood-front advancement. This confirms the effectiveness of the production/injection strategies that have been implemented in the field. Most of the logged wells that are located in mature areas showed good vertical sweep efficiency with very thin oil column remaining at the top of the reservoir including Zone-1. Most of the contacted intervals show very low oil saturation revealing excellent displacement efficiency, Fig. 3.5.

It has been also found that even in mature areas at the flanks where the lower zones are fully swept after decades of continuous production, Zone-1 remains largely un-swept. This can be explained by the lower rock quality of Zone-1 when compared to the under-lying zones and its limited thickness. Thereby, this zone could not historically be produced through conventional vertical wells. This created an opportunity to obtain direct production from this zone through dedicated producers.

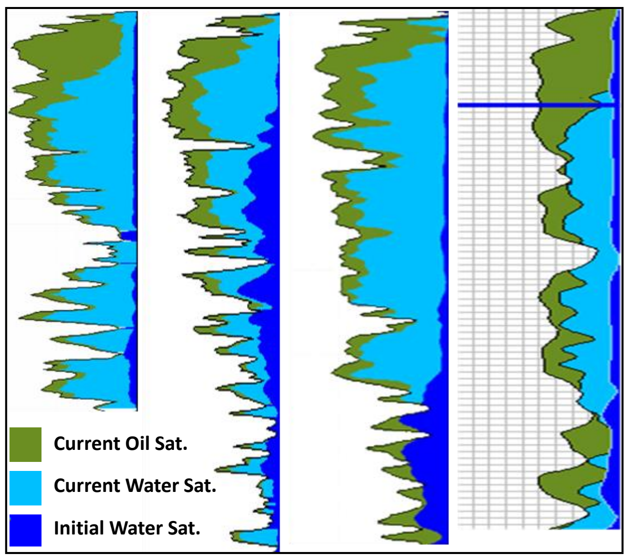

Figure 3.5: Recent saturation logs from wells located in different mature areas in the field

CHAPTER 4

OPTIMIZATION OF VERTICAL PLACEMENT AND LENGTH OF RESERVOIR CONTACT

After a comprehensive review, four wells from different parts of the field were selected for this study. These wells are vertical wells that cannot naturally flow due to high water cut, 85-90 %. Therefore, they are potential candidates for horizontal side-tracking. The objective of the study is to assess the impact of varying the vertical placement and the length of reservoir contact of the horizontal sections for these four wells. Properties of the targeted zone were reviewed. Porosity and thickness of the selected candidates and their off-set wells were evaluated. Sweep and remaining oil column were also assessed using recent saturation logs.

Since history matching is an essential step prior to running predictions, history matching of the selected wells and their off-set wells was carried out. History matching is adjusting a model of a reservoir until it closely reproduces the past behavior of a reservoir. The historical fluids production and pressures are matched as closely as possible. The accuracy of the history matching depends on the quality of the reservoir model and the quality and quantity of pressure and production data. Once a model has been efficiently history matched, it can be used to simulate future reservoir behavior with a higher degree of confidence.

This history-matched model was used to run predictions for the study. Sensitivity analysis at different vertical placement and length of reservoir contact were considered.

Predictions were run for more than 30 years and. Results included oil rate, cumulative oil production, water cut and reservoir pressure.

4.1 Evaluation of the Properties of the Targeted Zone

The first well that was selected was Well-A. The open-hole logs for the well and its off-set wells showed that the targeted zone within the area where Well-A is located has thickness ranging between 6 to 10 feet and a porosity ranging between 13 to 20 %, Fig 4.1. The open-hole logs of Well-B and its off-set wells showed that the targeted zone has thickness ranging between 5 to 10 feet and a porosity ranging between 18 to 25%, Fig. 4.2. Similarly, the open-hole logs of Well-C showed that the targeted zone has a thickness ranging between 5 to 15 feet and a porosity ranging between 22 to 25%, Fig. 4.3. Finally, the open-hole logs of Well-D and its off-set wells showed that the targeted zone has thickness ranging between 6 to 15 feet and a porosity ranging between 18 to 25%, Fig. 4.4.

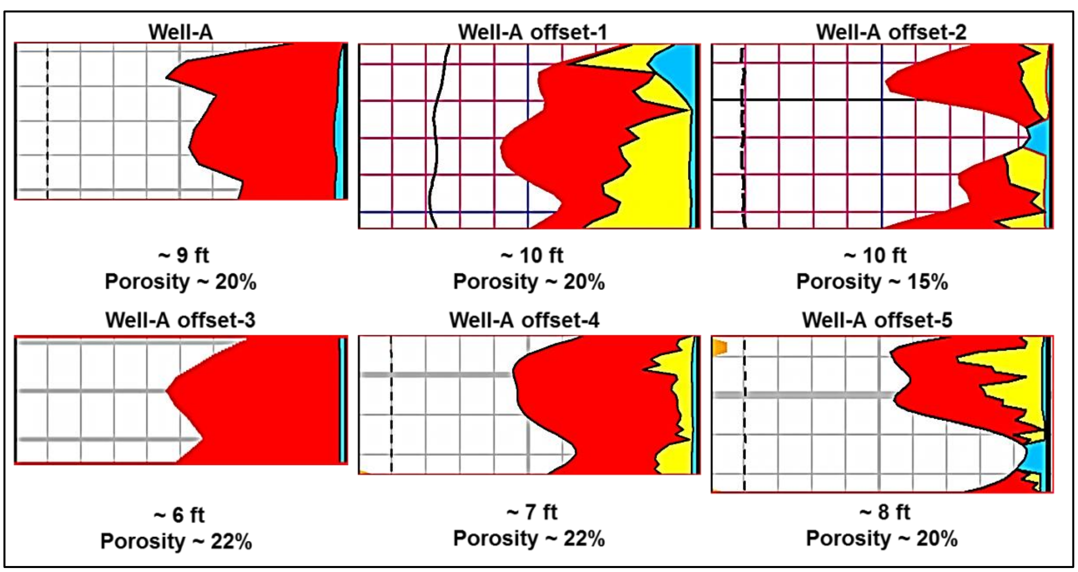

Figure 4.1: Zone-1 properties – Well-A

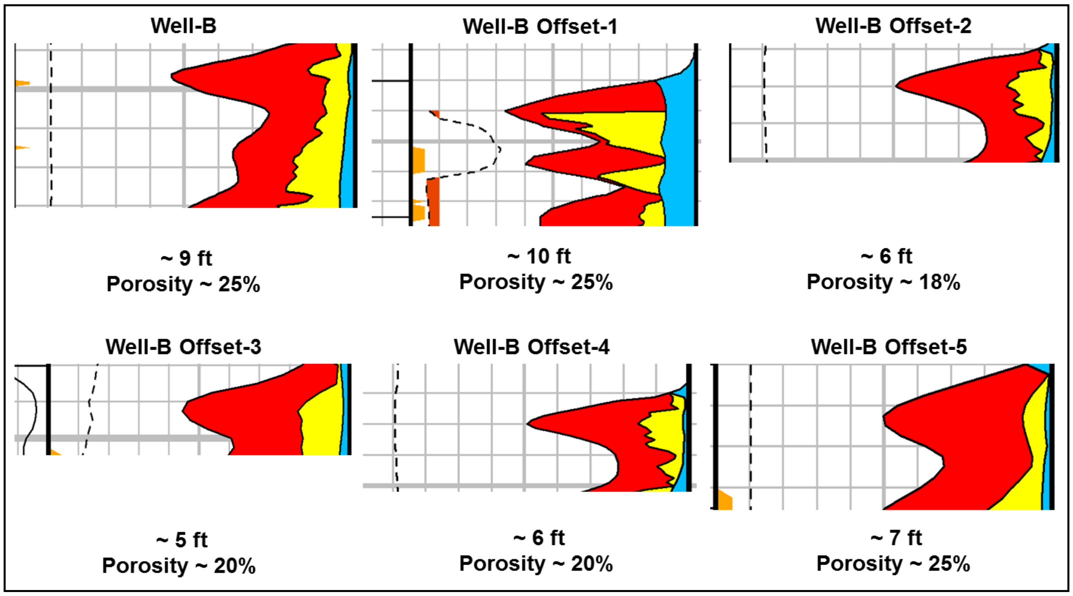

Figure 4.2: Zone-1 properties – Well-B

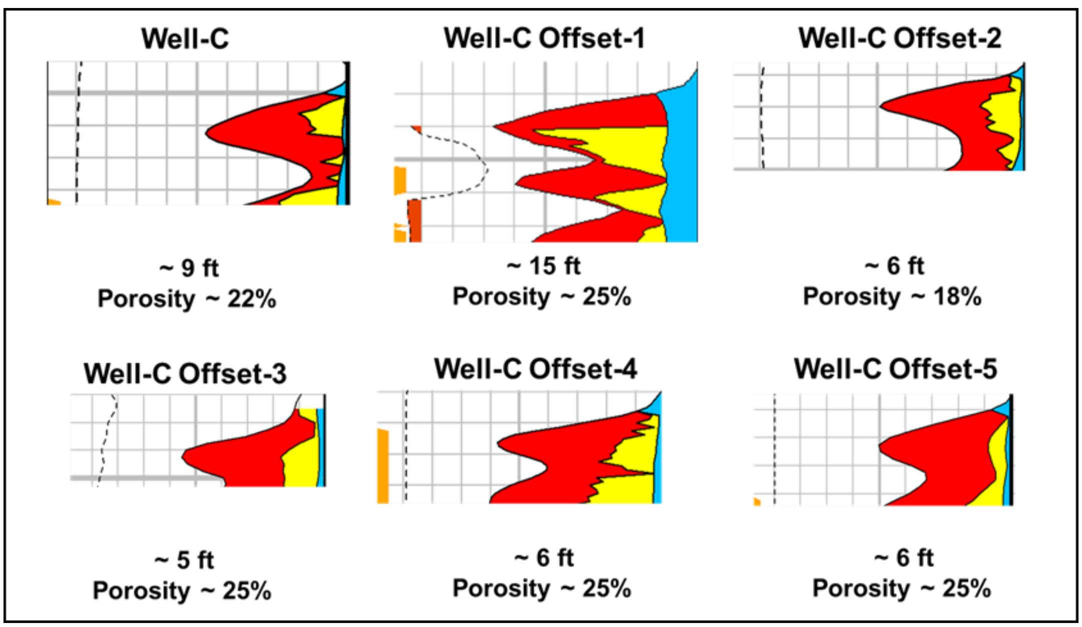

Figure 4.3: Zone-1 properties – Well-C

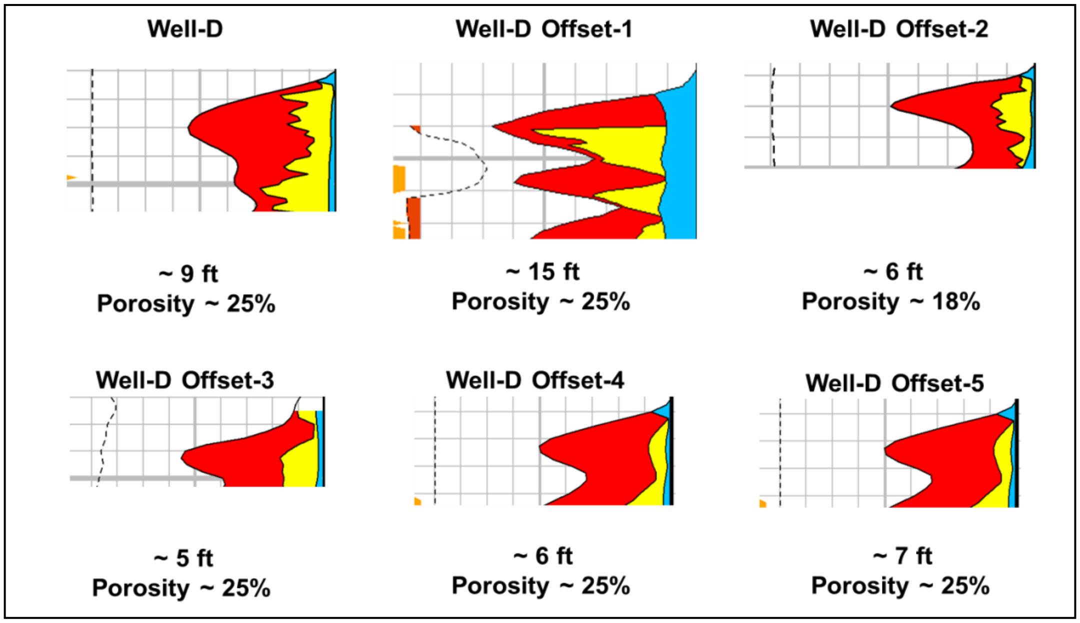

Figure 4.4: Zone-1 properties – Well-D

4.2 Assessment of the Remaining Oil

Sweep and remaining oil within the vicinity of the selected wells were assessed using recent saturation logs. Logs that have been obtained include Carbon/Oxygen (C/O) and resistivity logs. Recent logs, run in the candidate wells and/or their off-set wells, showed good bottoms-up sweep demonstrated by the lower zones being swept with only some remaining oil column (ROC) at the top ranging between 5 to 20 ft, Table 4.1. At the same time and as expected, these logs showed that the targeted zone, Zone-1, is un-swept. The logs of Well-A, B, C and D are displayed in Fig. 4.5, 4.6, 4.7 and 4.8, respectively. The remaining oil is highlighted by a red box in each of these figures.

Table 4.1: Remaining Oil column in the areas of the candidate wells

	Remaining Oil Column, ft
Well-A	15 - 20
Well-B	5 - 10
Well-C	~ 15
Well-D	10 - 15

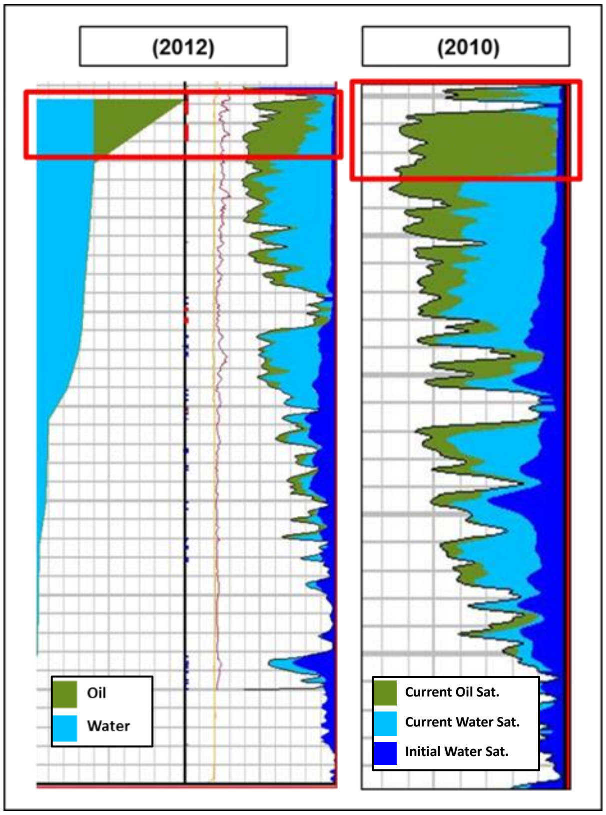

Figure 4.5: Well-A - Assessment of sweep & ROC

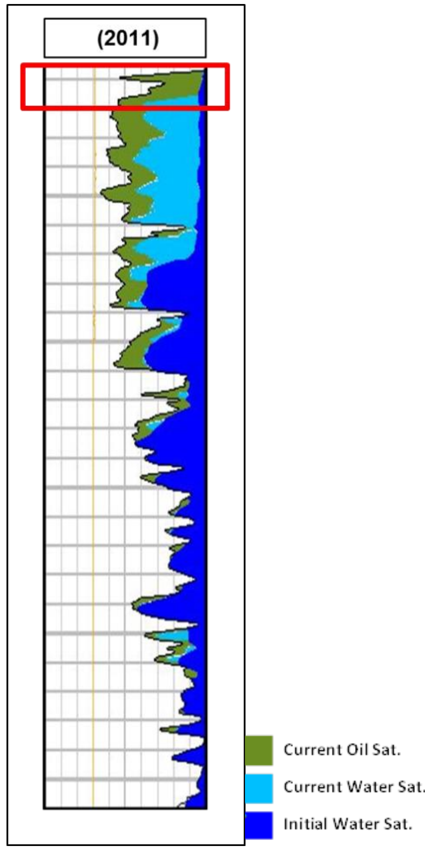

Figure 4.6: Well-B - Assessment of sweep & ROC

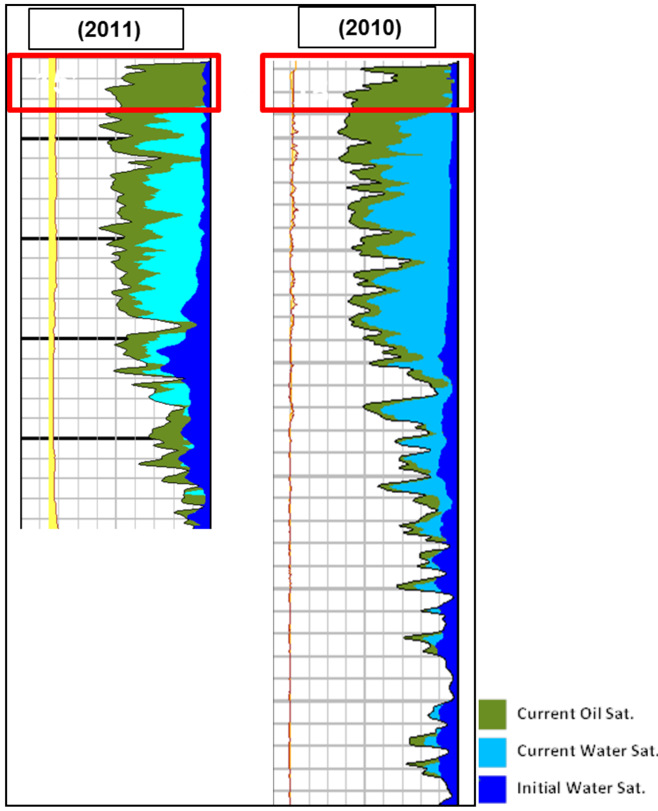

Figure 4.7: Well-C - Assessment of sweep & ROC

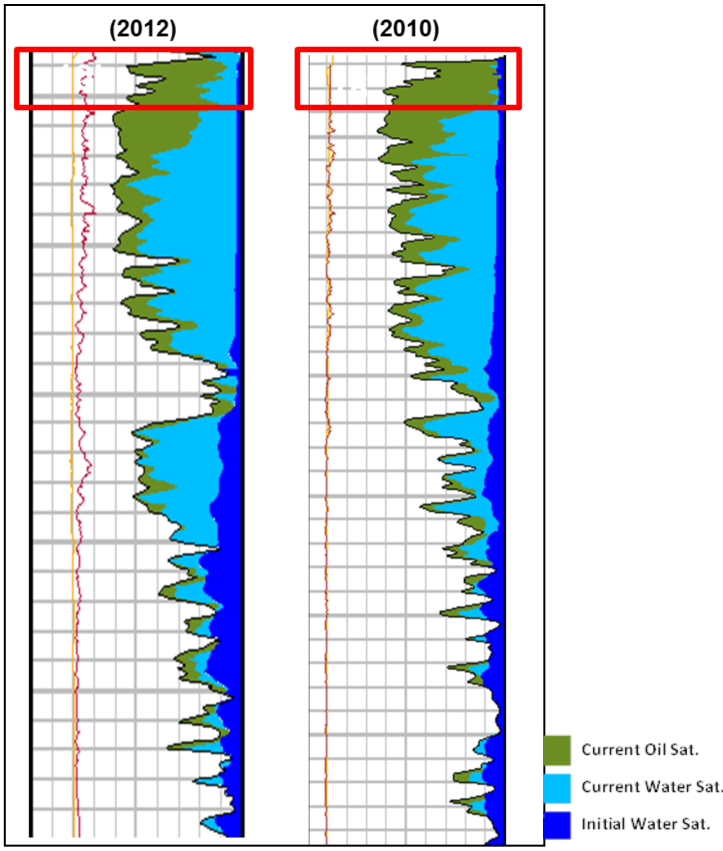

Figure 4.8: Well-D - Assessment of sweep & ROC

4.3 History Matching

History matching is a vital step toward achieving prediction results at a high degree of confidence. The first parameter that was history matched is the static bottom hole pressure (SIBHP). After then, the water cut was matched. Significant amount of actual data of the selected wells and their off-sets including fluids rate and SIBHP were matched. The wells have been producing for many years, and thereby, a sufficient amount of data could be used for the history matching process, Tables 4.2, 4.3, 4.4 & 4.5. The main parameter that was adjusted in order to achieve an acceptable match was permeability (k). A map of transient test to model kh was constructed using all available and valid test data. The historical performance of the selected wells and their off-sets could be reproduced, Figs. 4.9-4.56.

Table 4.2: Well-A and Off-sets start of production

	Start of Production	**# of Years History Matched**
Well-A	1954	58
Off-set-1	1998	14
Off-set-2	1995	17
Off-set-3	1996	16

Table 4.3: Well-B and Off-sets start of production

	Start of Production	**# of Years History Matched**
Well-B	1992	20
Off-set-1	1993	19
Off-set-2	1993	19
Off-set-3	1991	21

Table 4.4: Well-C and Off-sets start of production

	Start of Production	**# of Years History Matched**
Well-C	1995	17
Off-set-1	1986	26
Off-set-2	1991	21
Off-set-3	1993	19

Table 4.5: Well-D and Off-sets start of production

	Start of Production	# of Years History Matched
Well-D	1995	17
Off-set-1	1969	43
Off-set-2	1996	16
Off-set-3	1994	18

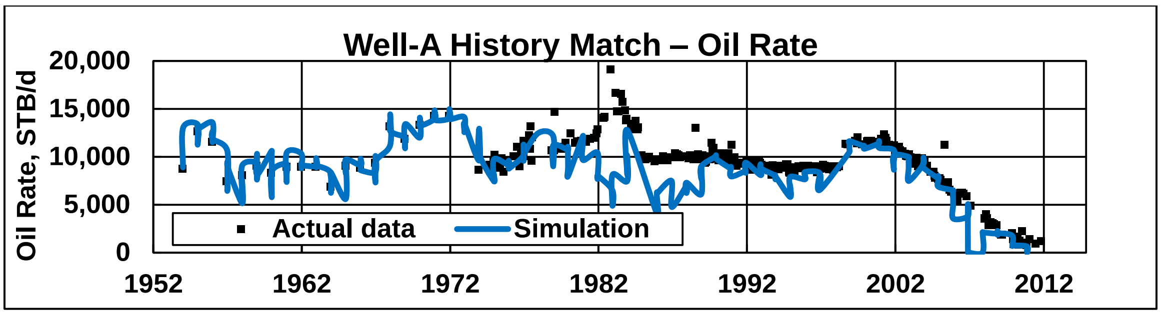

Figure 4.9 Well-A History Match - Oil Rate

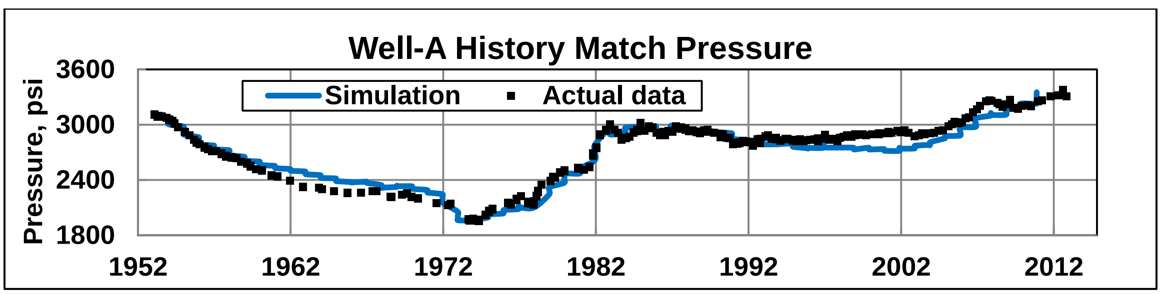

Figure 4.10 Well-A History Match – Pressure

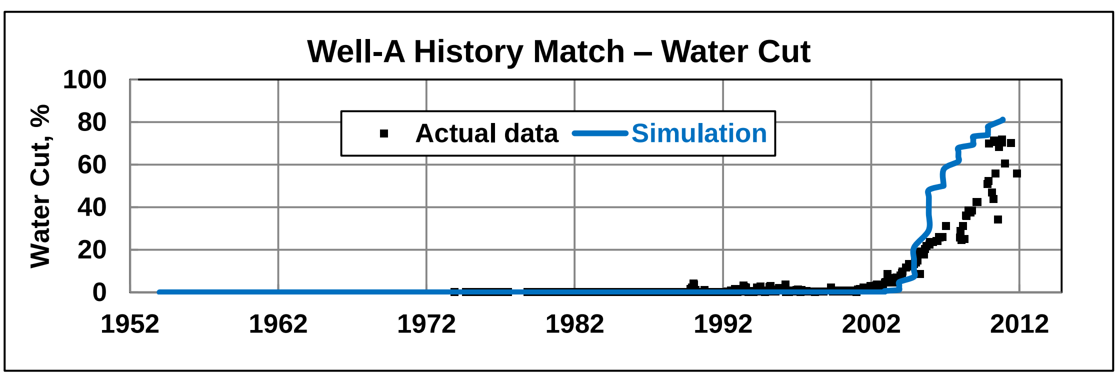

Figure 4.11: Well-A History Match – Water Cut

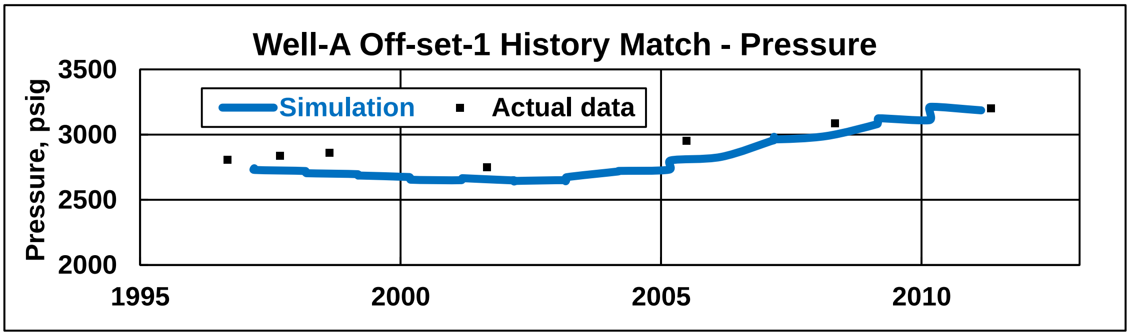

Figure 4.12: Well-A Off-set-1 History Match - Pressure

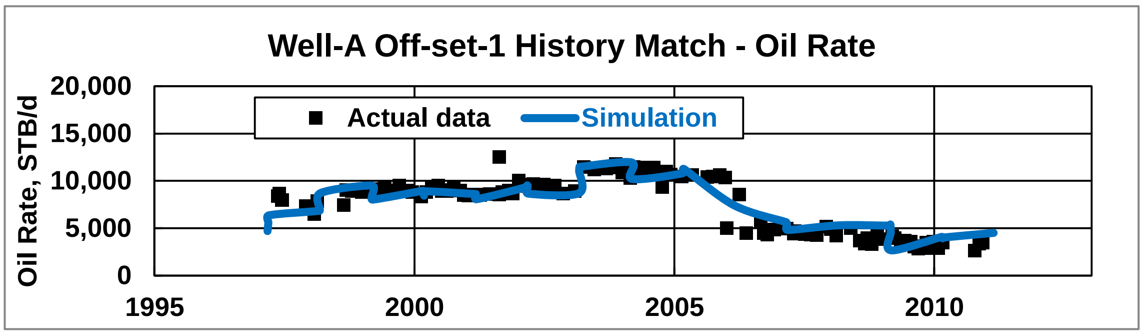

Figure 4.13: Well-A Off-set-1 History Match - Oil Rate

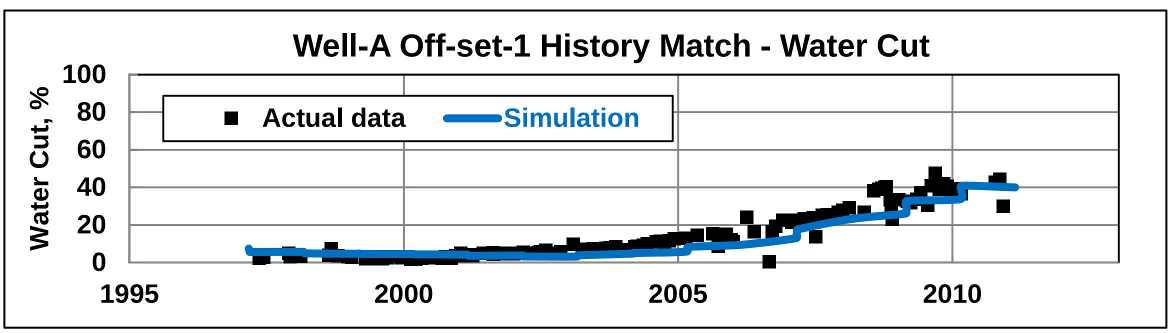

Figure 4.14: Well-A Off-set-1 History Match - Water Cut

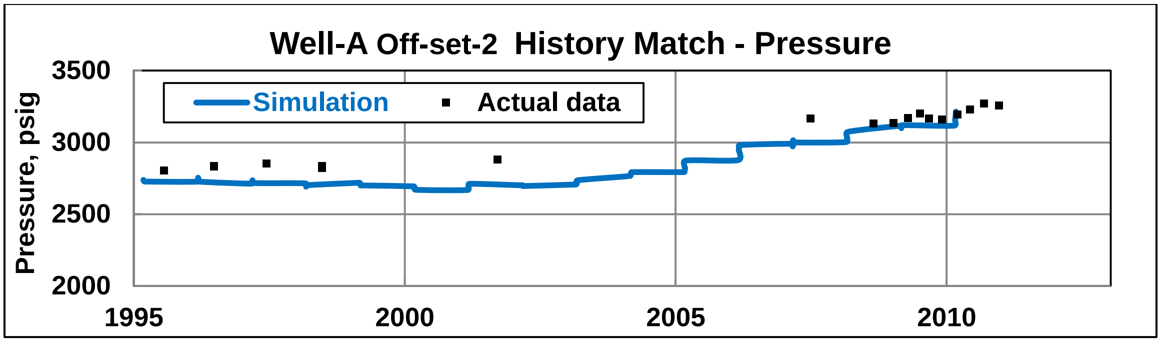

Figure 4.15: Well-A Off-set-2 History Match – Pressure

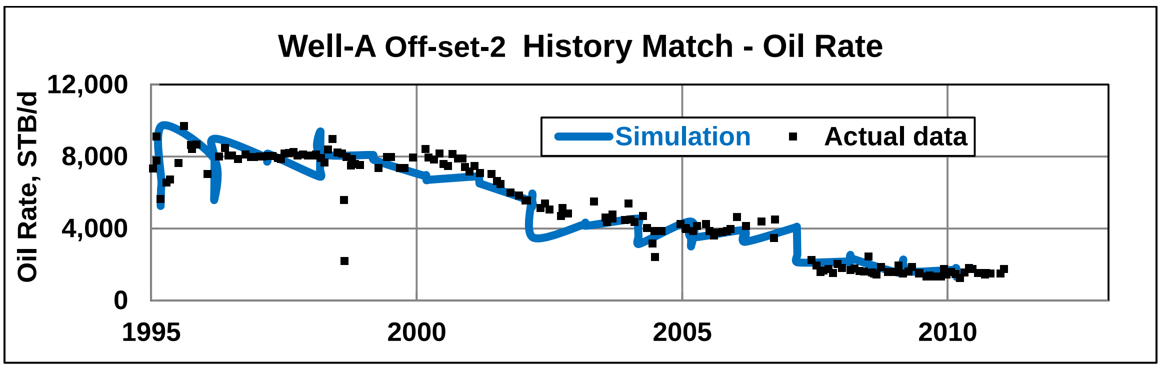

Figure 4.16: Well-A Off-set-2 History Match - Oil Rate

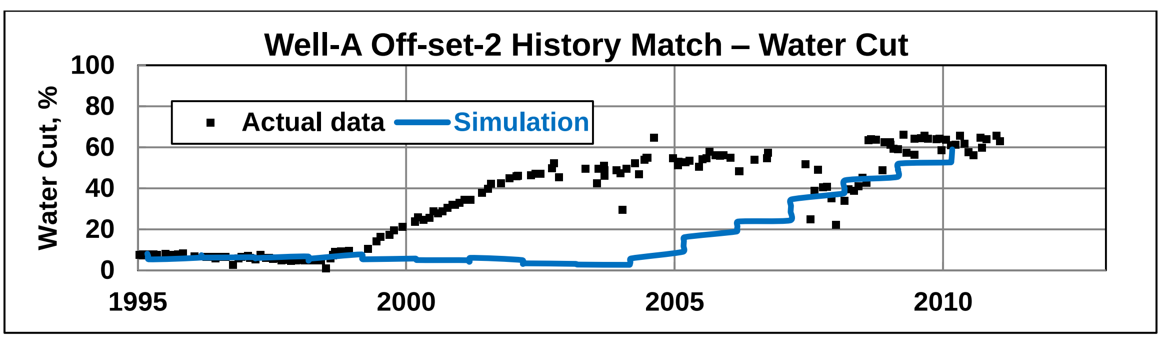

Figure 4.17: Well-A Off-set-2 History Match – Water Cut

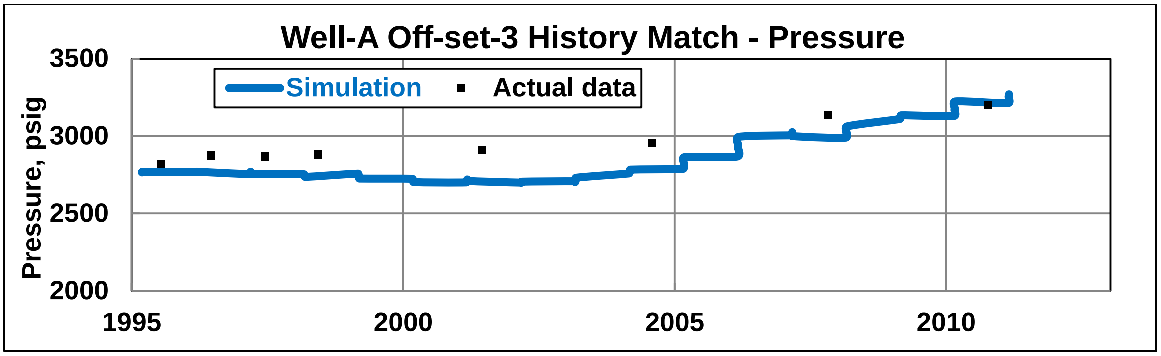

Figure 4.18: Well-A Off-set-3 History Match – Pressure

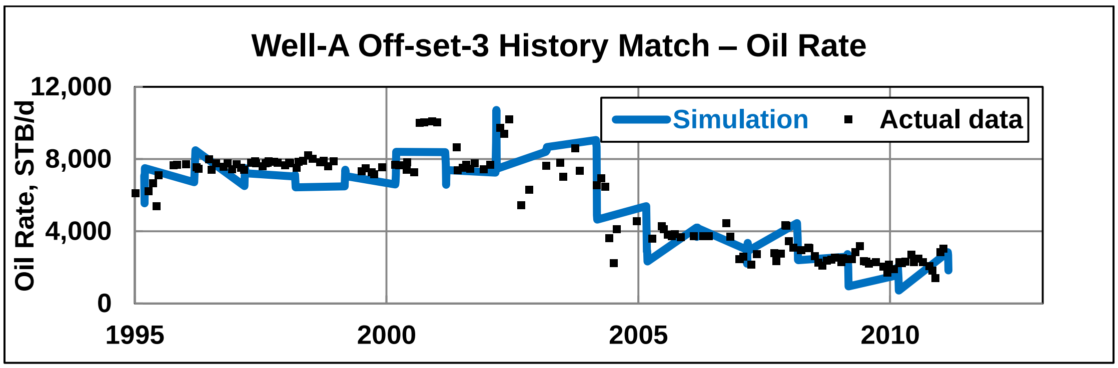

Figure 4.19: Well-A Off-set-3 History Match – Oil Rate

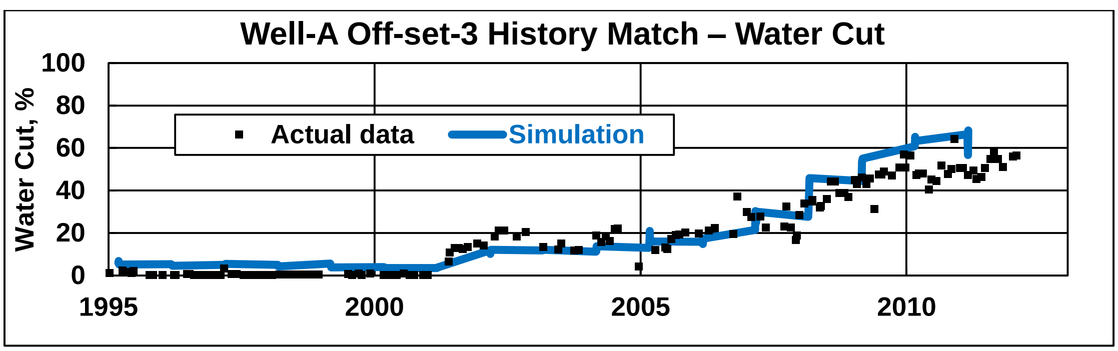

Figure 4.20: Figure 27 Well-A Off-set-3 History Match – Water Cut

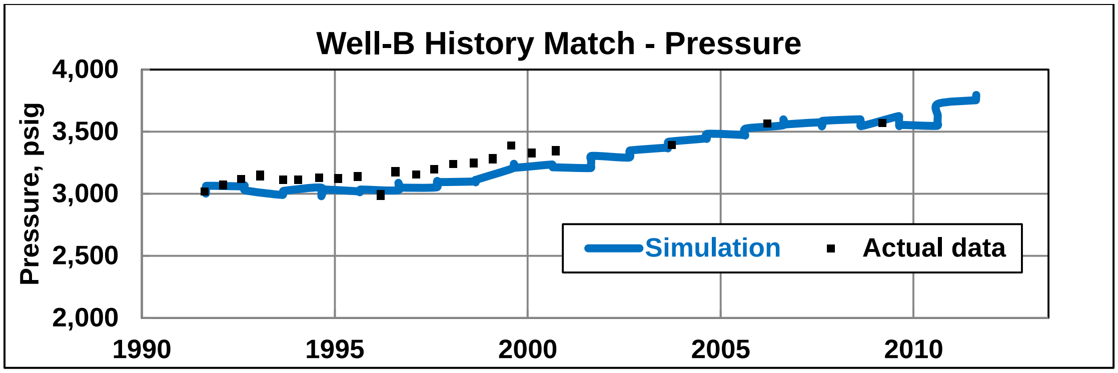

Figure 4.21: Well-B History Match – Pressure

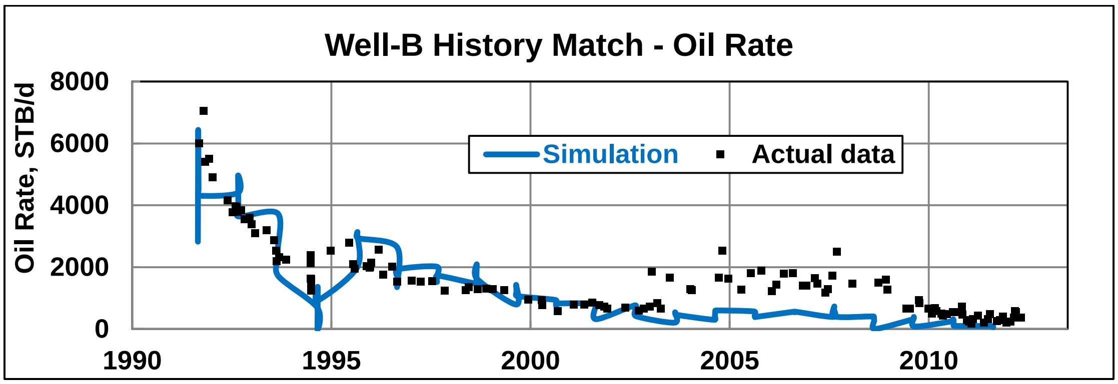

Figure 4.22: Well-B History Match - Oil Rate

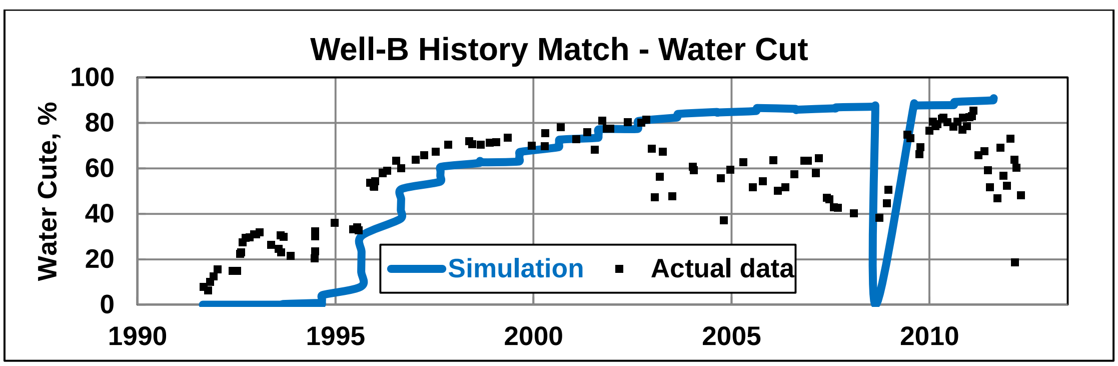

Figure 4.23: Well-B History Match - Water Cut

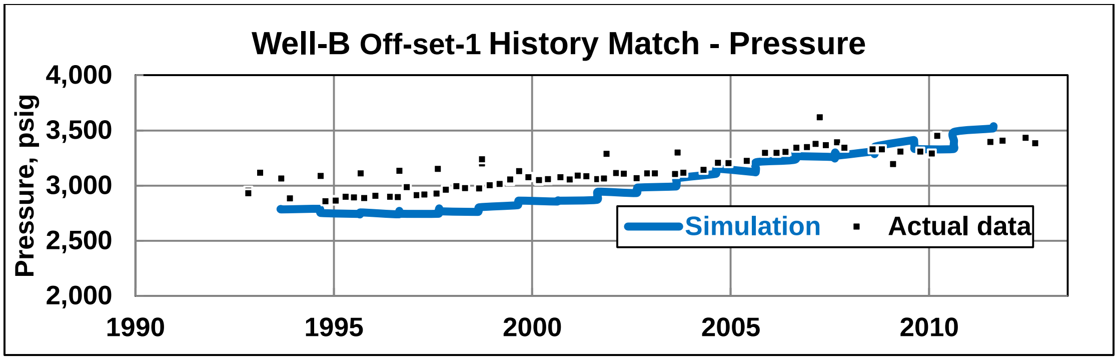

Figure 4.24: Well-B Off-set-1 History Match – Pressure

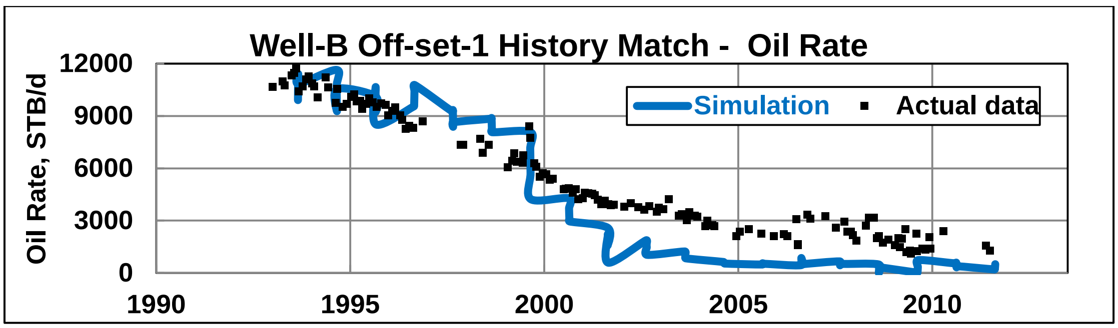

Figure 4.25: Well-B Off-set-1 History Match - Oil Rate

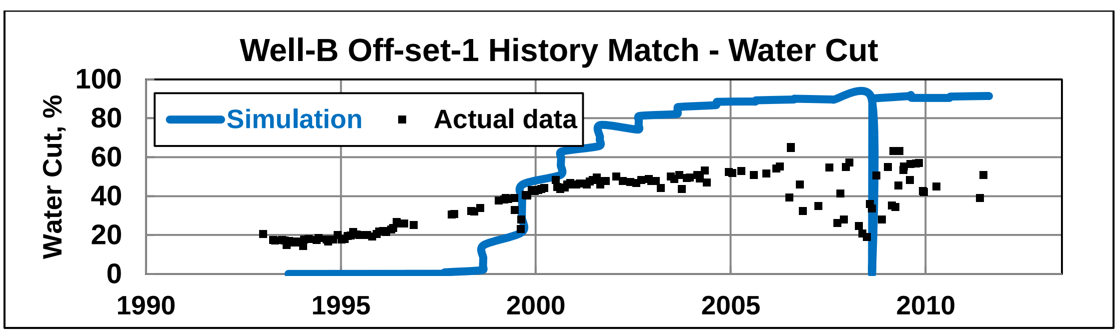

Figure 4.26: Well-B Off-set-1 History Match - Water Cut

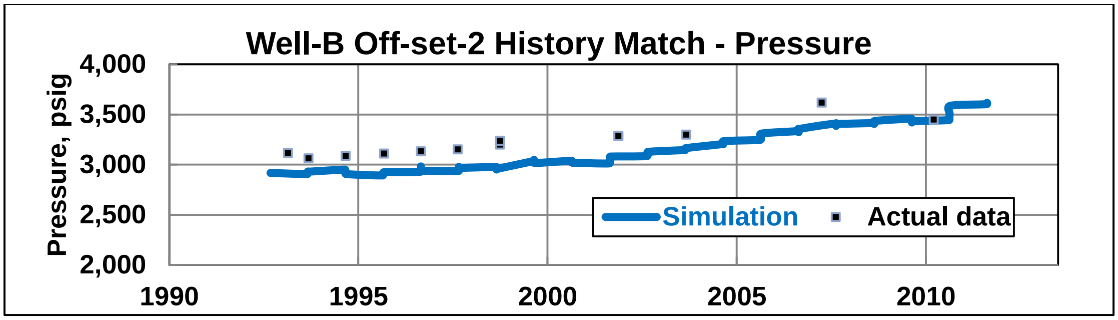

Figure 4.27: Well-B Off-set-2 History Match – Pressure

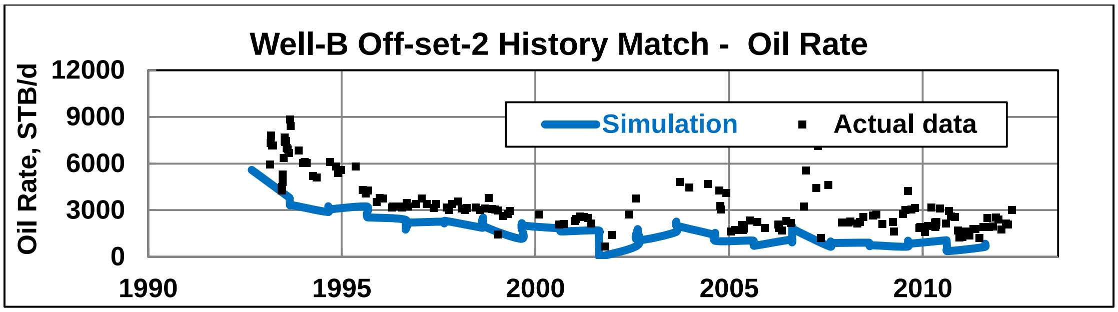

Figure 4.28: Well-B Off-set-2 History Match - Oil Rate

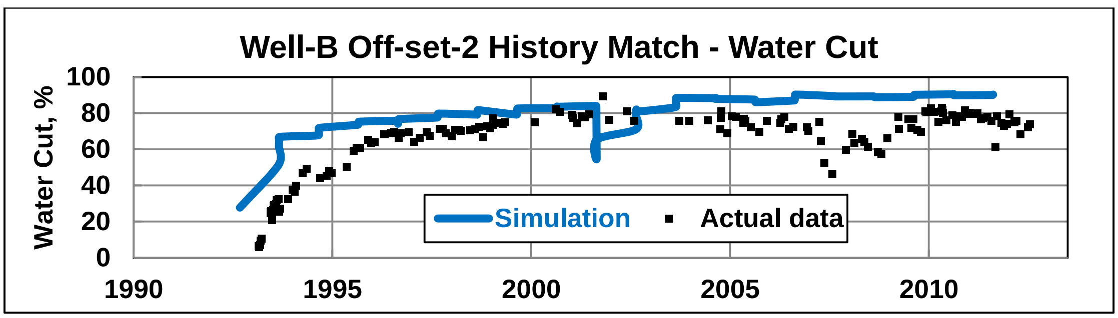

Figure 4.29: Well-B Off-set-2 History Match - Water Cut

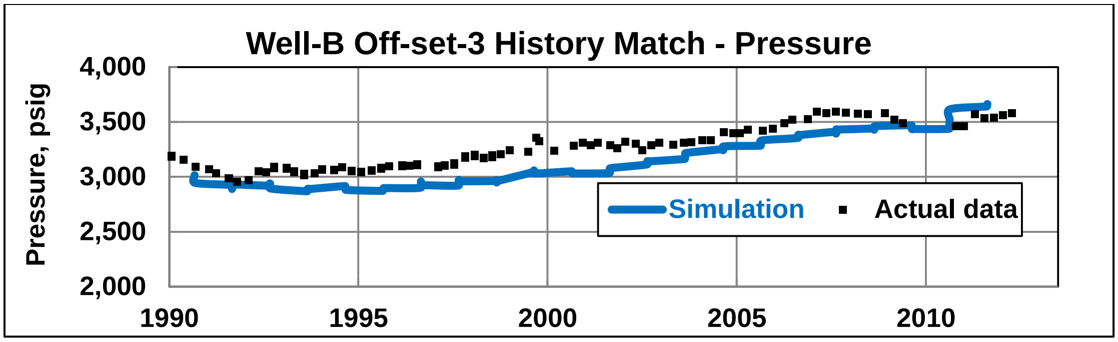

Figure 4.30: Well-B Off-set-3 History Match – Pressure

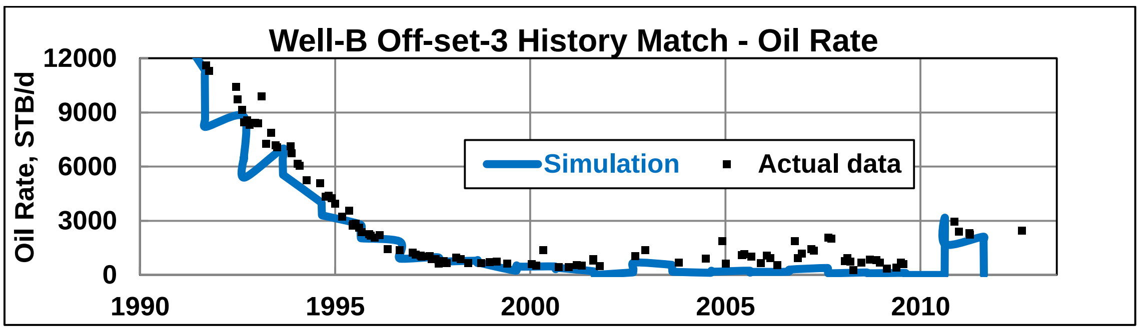

Figure 4.31: Well-B Off-set-3 History Match - Oil Rate

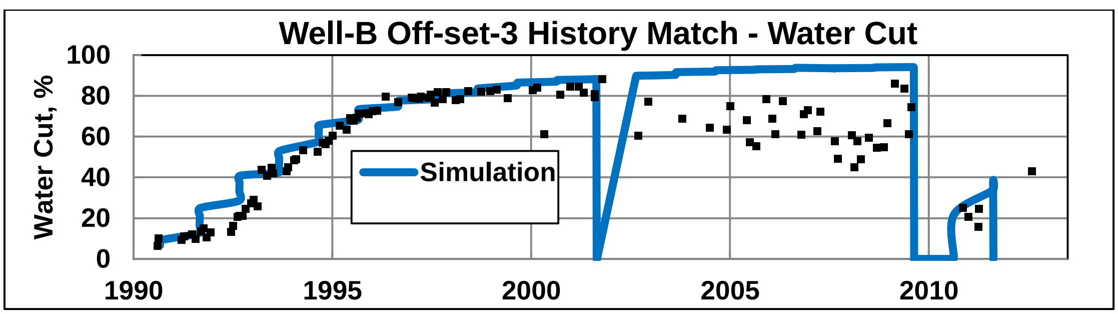

Figure 4.32: Well-B Off-set-3 History Match - Water Cut

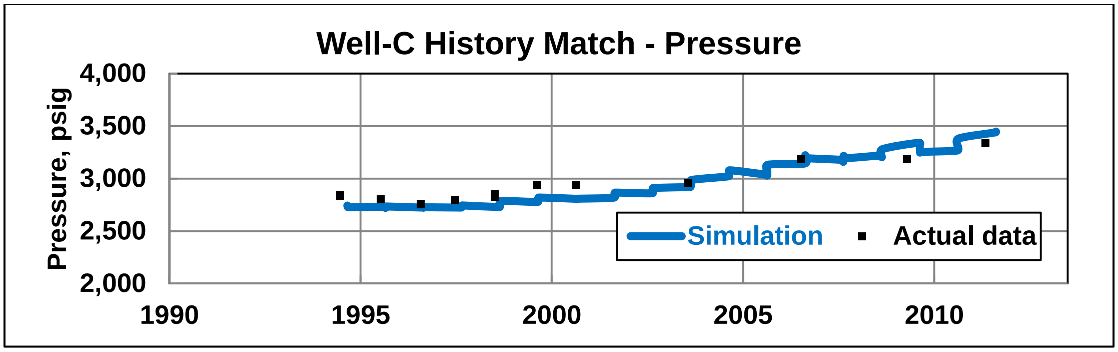

Figure 4.33: Well-C History Match – Pressure

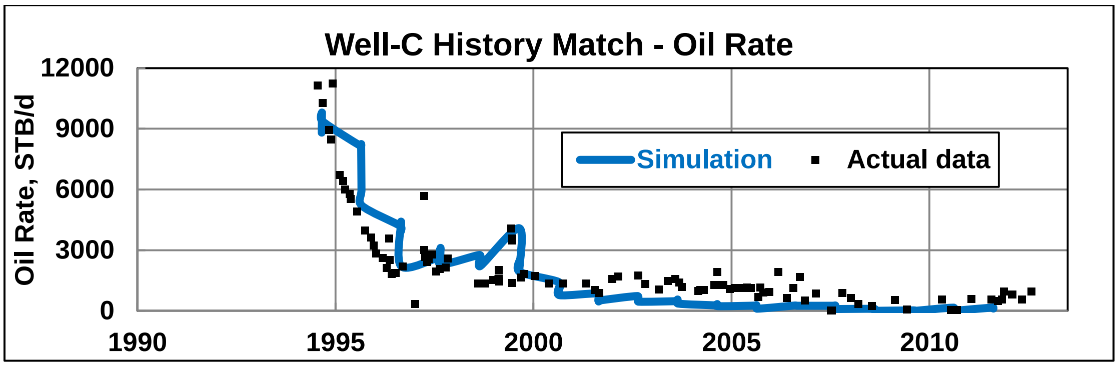

Figure 4.34: Well-C History Match - Oil Rate

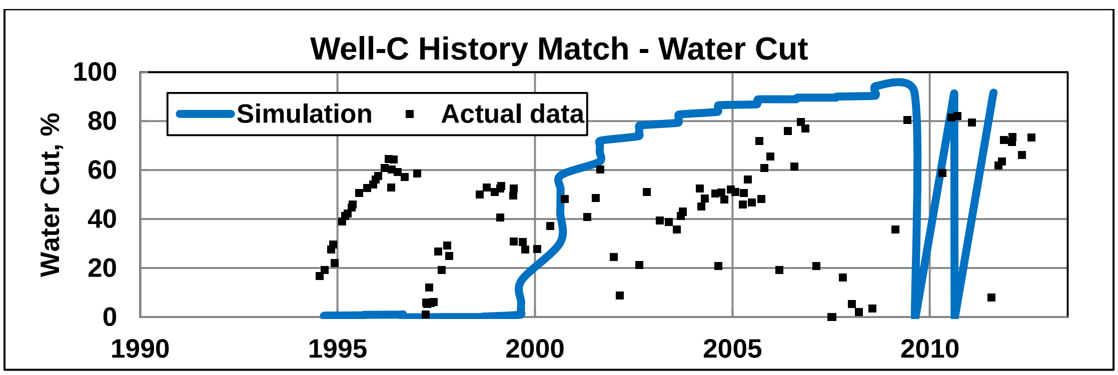

Figure 4.35: Well-C History Match - Water Cut

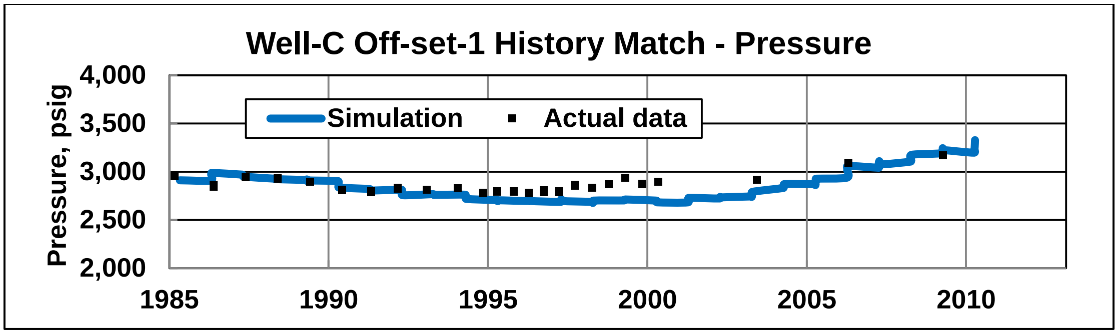

Figure 4.36: Well-C Off-set-1 History Match – Pressure

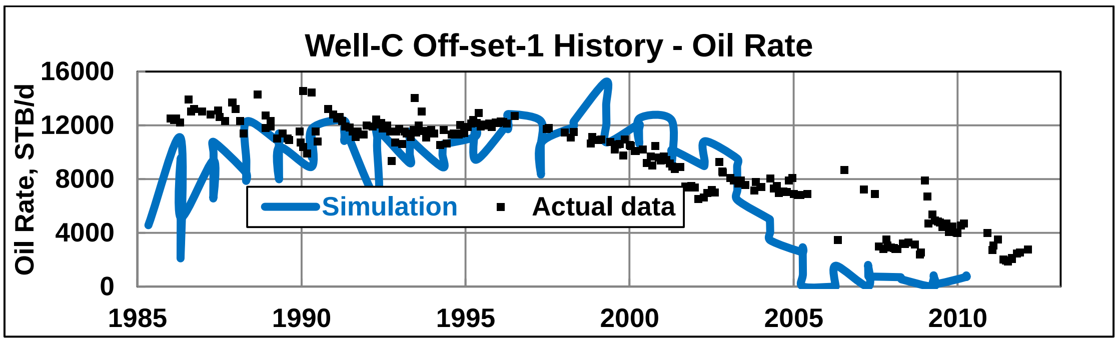

Figure 4.37: Well-C Off-set-1 History - Oil Rate

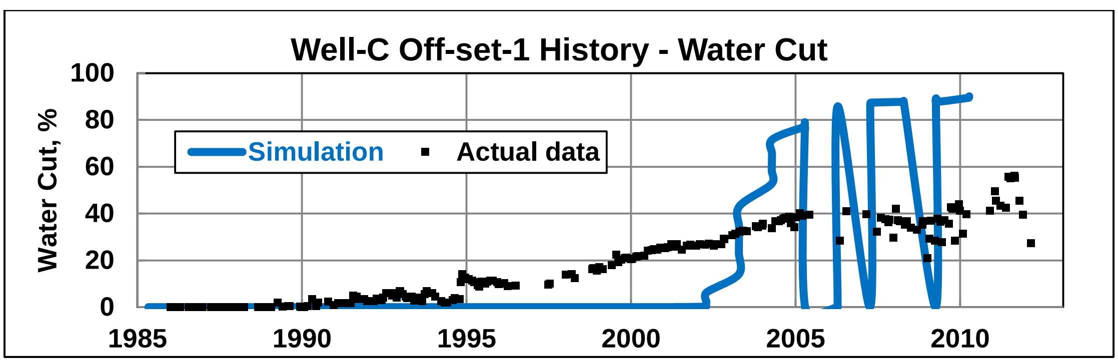

Figure 4.38: Well-C Off-set-1 History - Water Cut

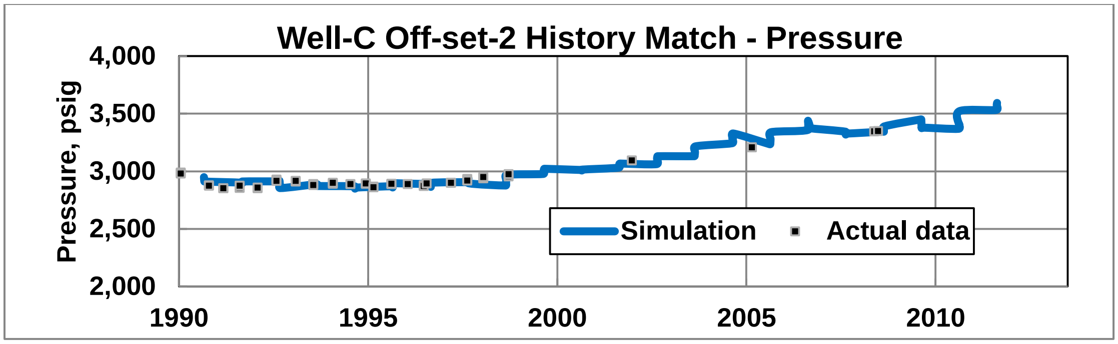

Figure 4.39: Well-C Off-set-2 History Match – Pressure

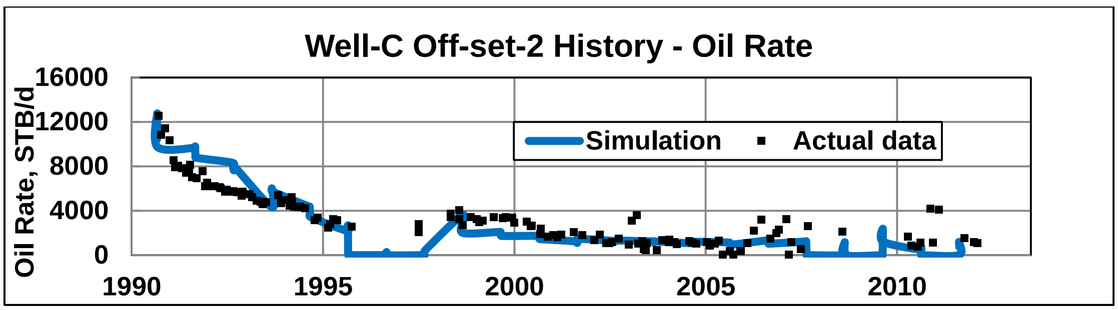

Figure 4.40: Well-C Off-set-2 History - Oil Rate

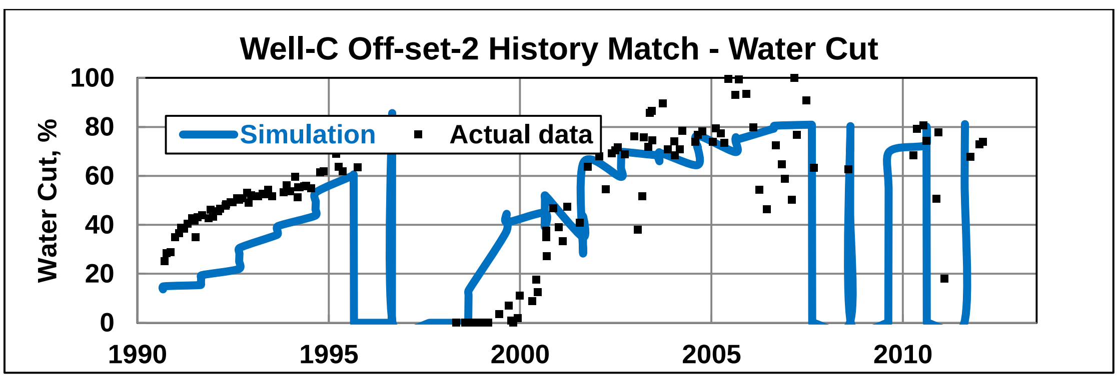

Figure 4.41: Well-C Off-set-2 History Match - Water Cut

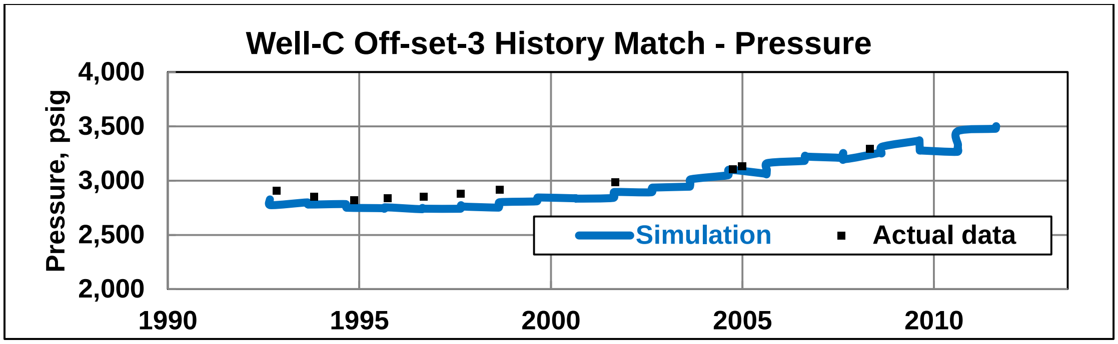

Figure 4.42: Well-C Off-set-3 History Match – Pressure

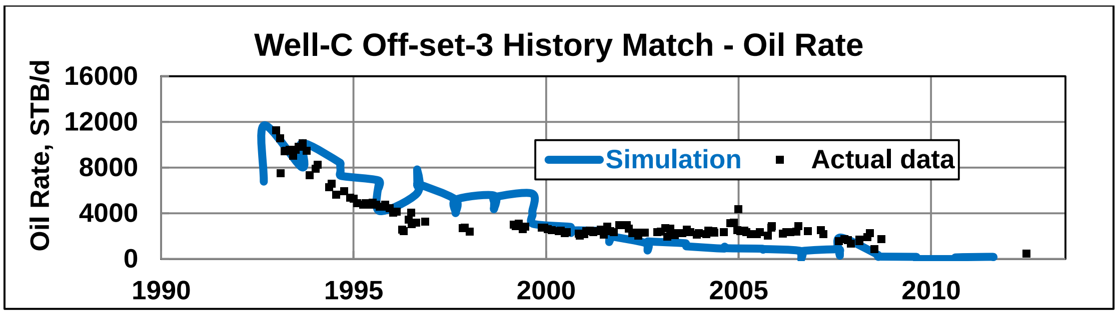

Figure 4.43: Well-C Off-set-3 History Match - Oil Rate

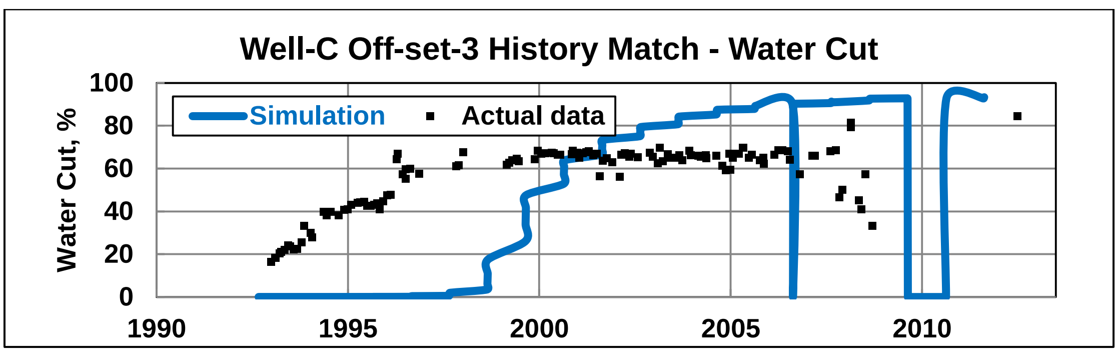

Figure 4.44: Well-C Off-set-3 History Match - Water Cut

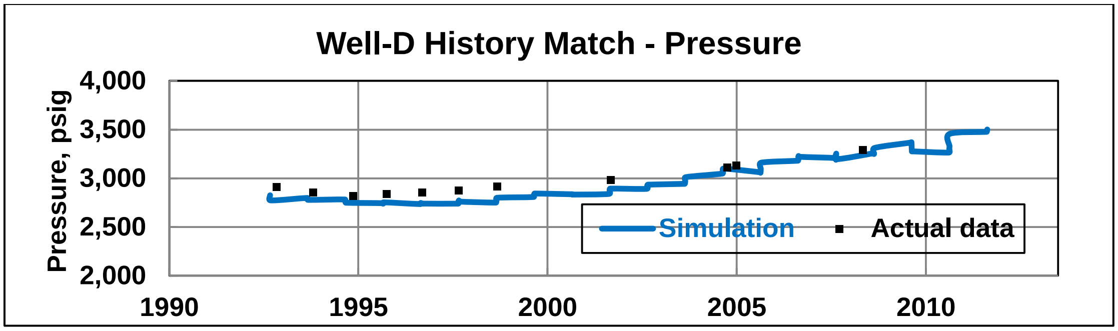

Figure 4.45: Well-D History Match – Pressure

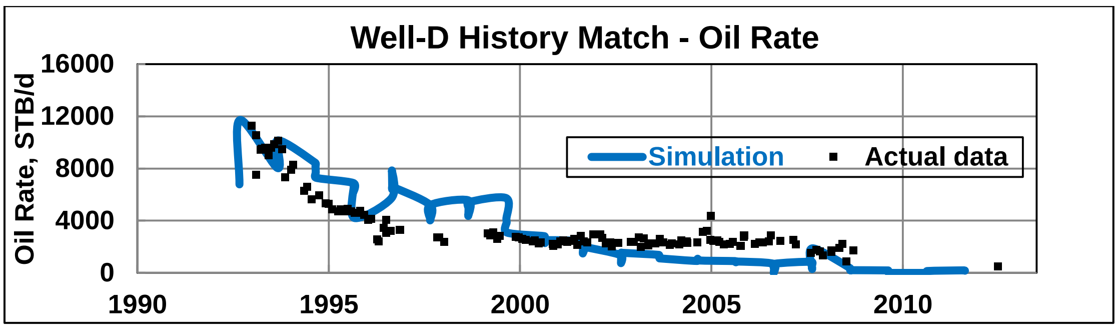

Figure 4.46: Well-D History Match - Oil Rate

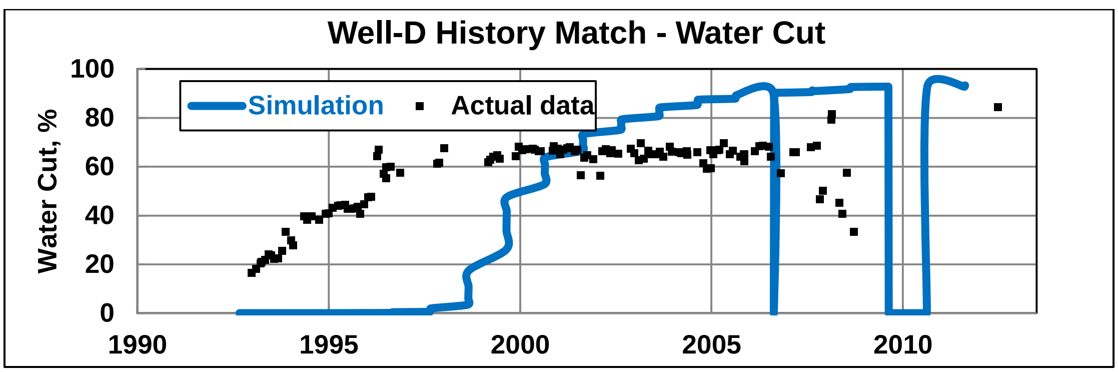

Figure 4.47: Well-D History Match - Water Cut

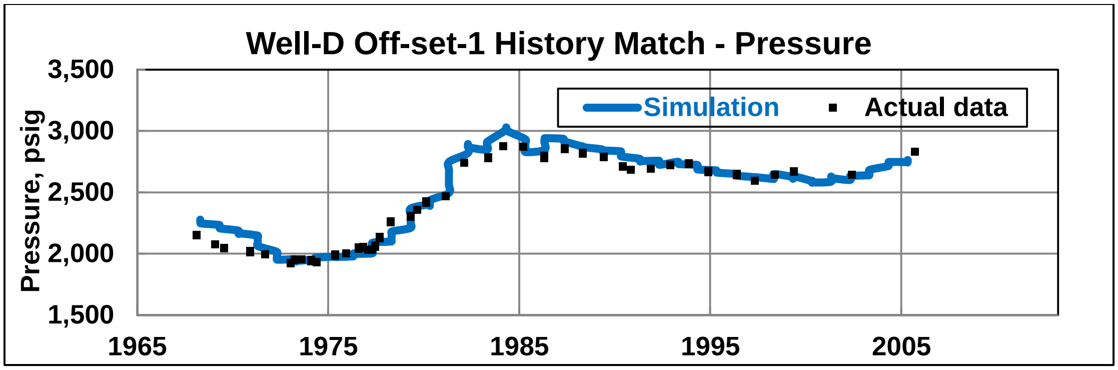

Figure 4.48: Well-D Off-set-1 History Match – Pressure

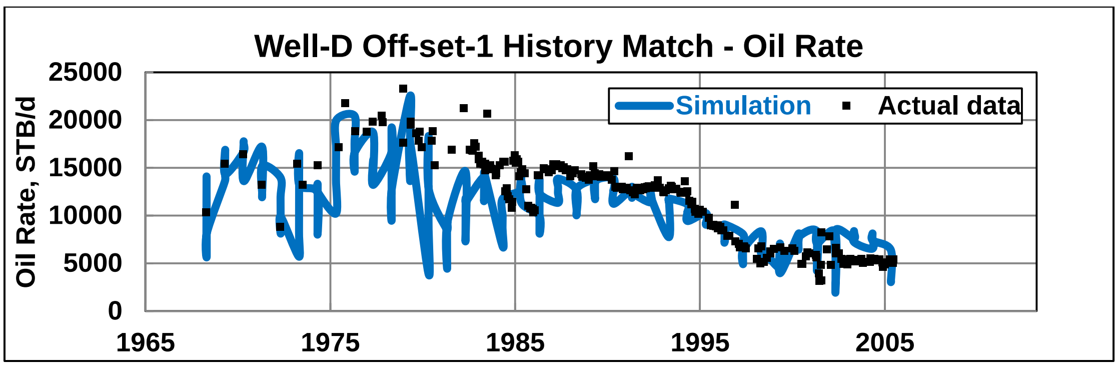

Figure 4.49: Well-D Off-set-1 History Match - Oil Rate

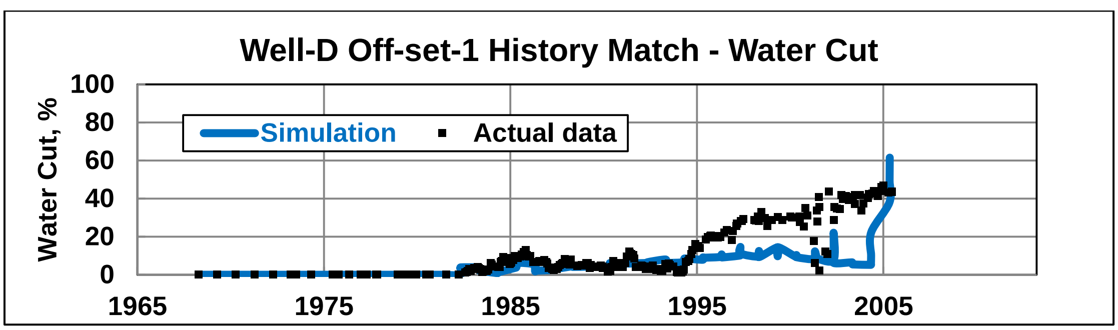

Figure 4.50: Well-D Off-set-1 History Match - Water Cut

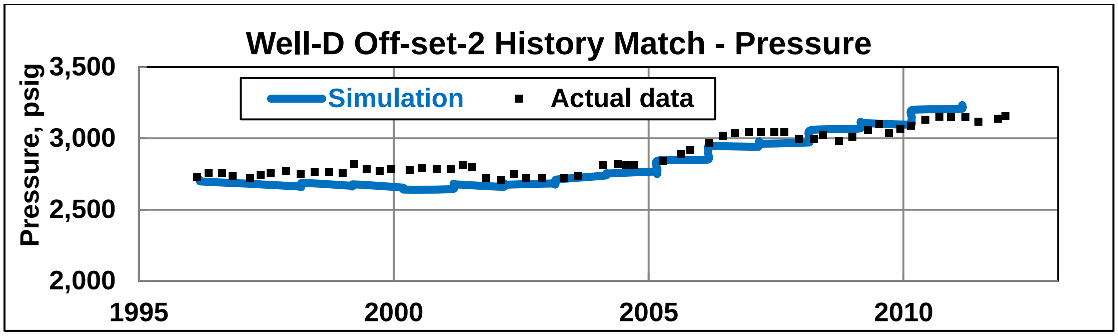

Figure 4.51: Well-D Off-set-2 History Match – Pressure

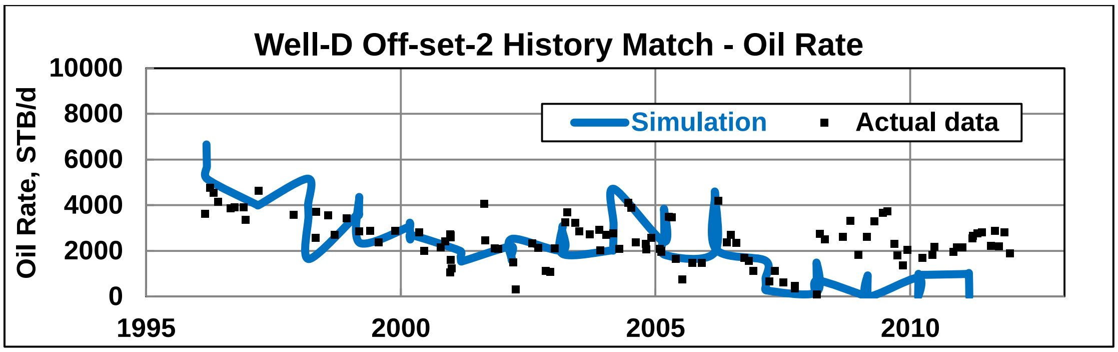

Figure 4.52: Well-D Off-set-2 History Match - Oil Rate

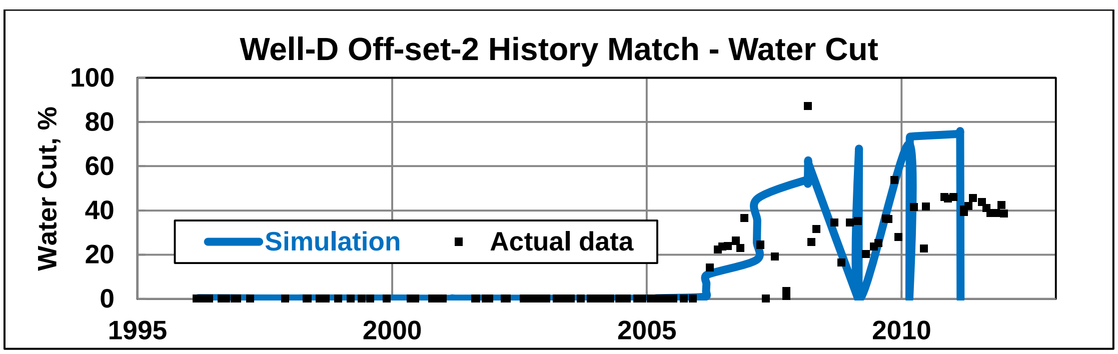

Figure 4.53: Well-D Off-set-2 History Match - Water Cut

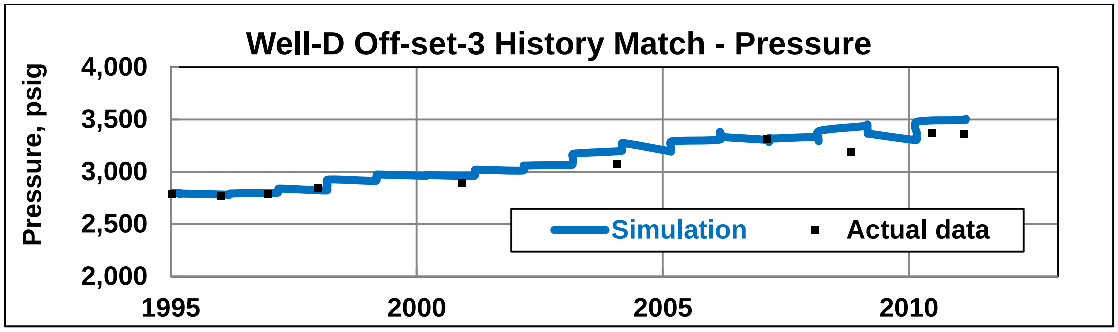

Figure 4.54: Well-D Off-set-3 History Match – Pressure

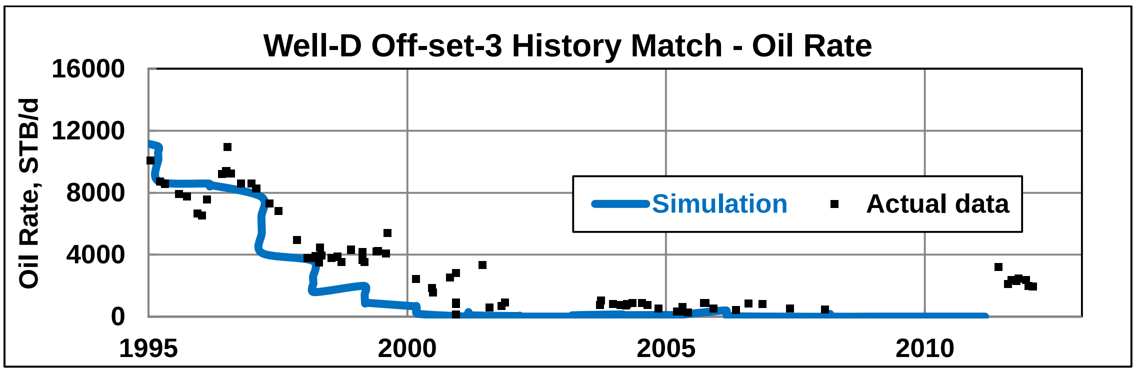

Figure 4.55: Well-D Off-set-3 History Match - Oil Rate

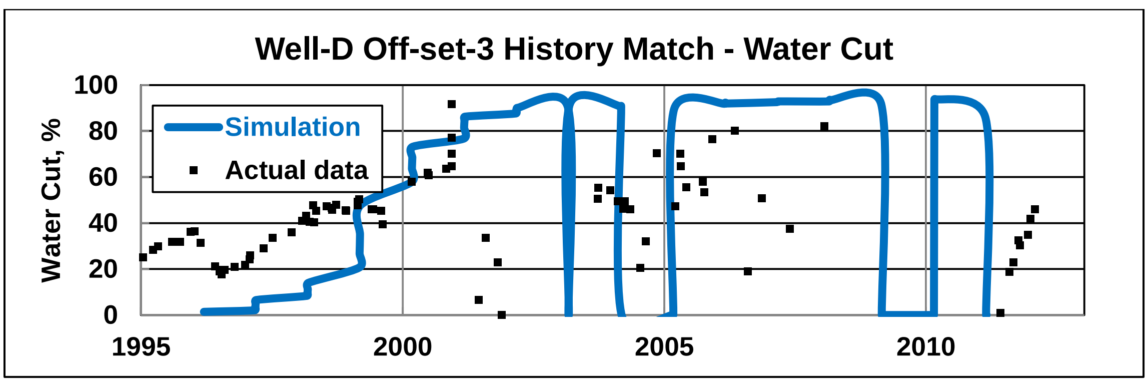

Figure 4.56: Well-D Off-set-3 History Match - Water Cut

4.4 Prediction Runs

4.4.1 Sensitivity Analysis of Vertical Placement

After achieving a satisfactory history match, prediction cases were designed. The objective of these prediction runs was to assess the future performance of placing a 4,000 ft horizontal lateral in the targeted zone for each of the four selected wells. All of the parameters were kept constant except the vertical placement. The constrains include:

- Initial rate = 3000 STB/d
- Minimum FBHP = 2000 psig
- Minimum FWHP = 160 psig
- Maximum water cut = 85 %

For each of the selected wells, three scenarios were simulated. These scenarios were placing the lateral at the top layer of the targeted zone (L-1), the middle layer (L-2) and the bottom layer (L-3). Long term predictions of more than 30 years were utilized. Results were evaluated based on oil rate, water cut and cumulative oil production. In all of the cases, the model indicates that placing the horizontal lateral in (L-1) results in superior performance with higher cumulative oil production and lower water cut and longer well life when compared to placement in L-2 and L-3, Figs. 4.57-4.68.

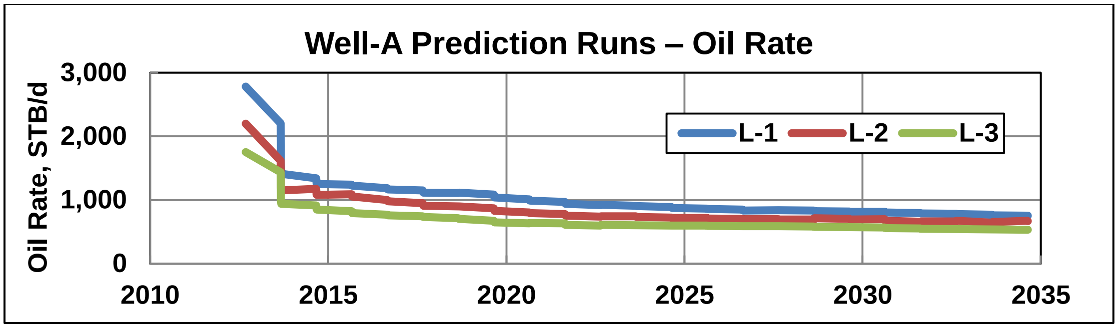

Figure 4.57: Well-A Prediction Runs – Oil Rate

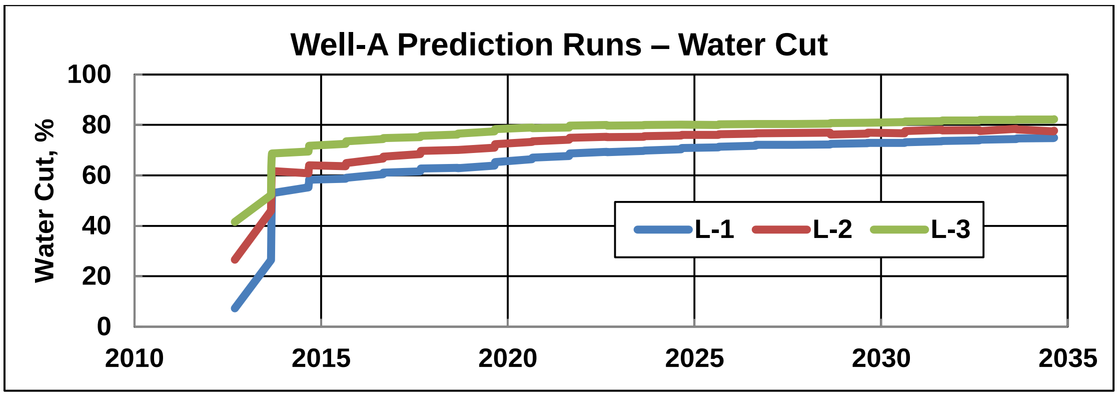

Figure 4.58: Well-A Prediction Runs – Water Cut

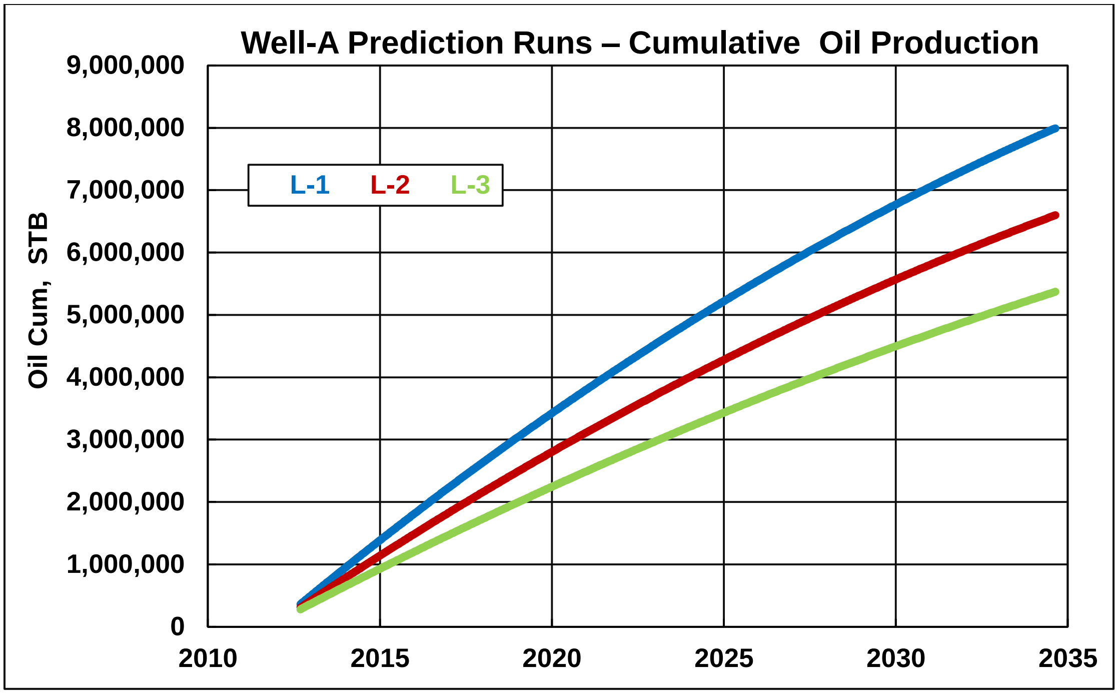

Figure 4.59: Well-A Prediction Runs – Cumulative Oil Production

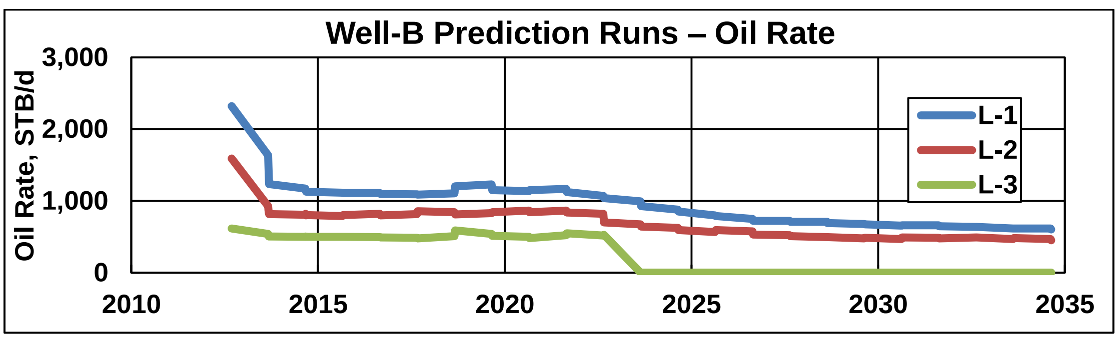

Figure 4.60: Well-B Prediction Runs – Oil Rate

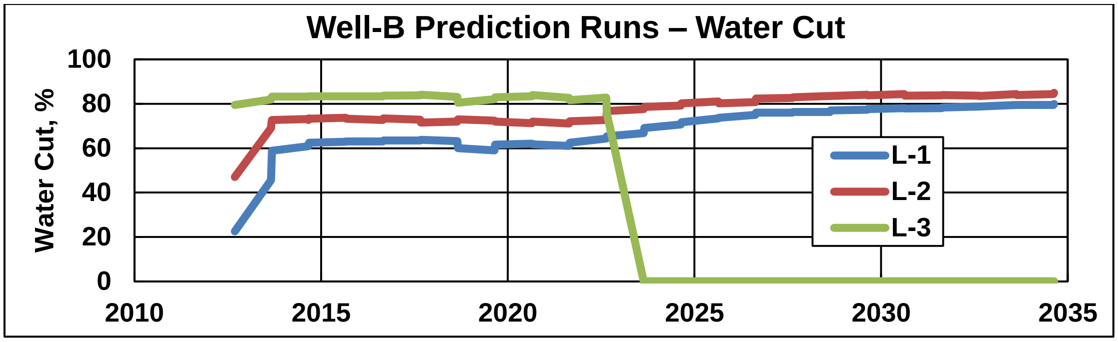

Figure 4.61: Well-B Prediction Runs – Water Cut

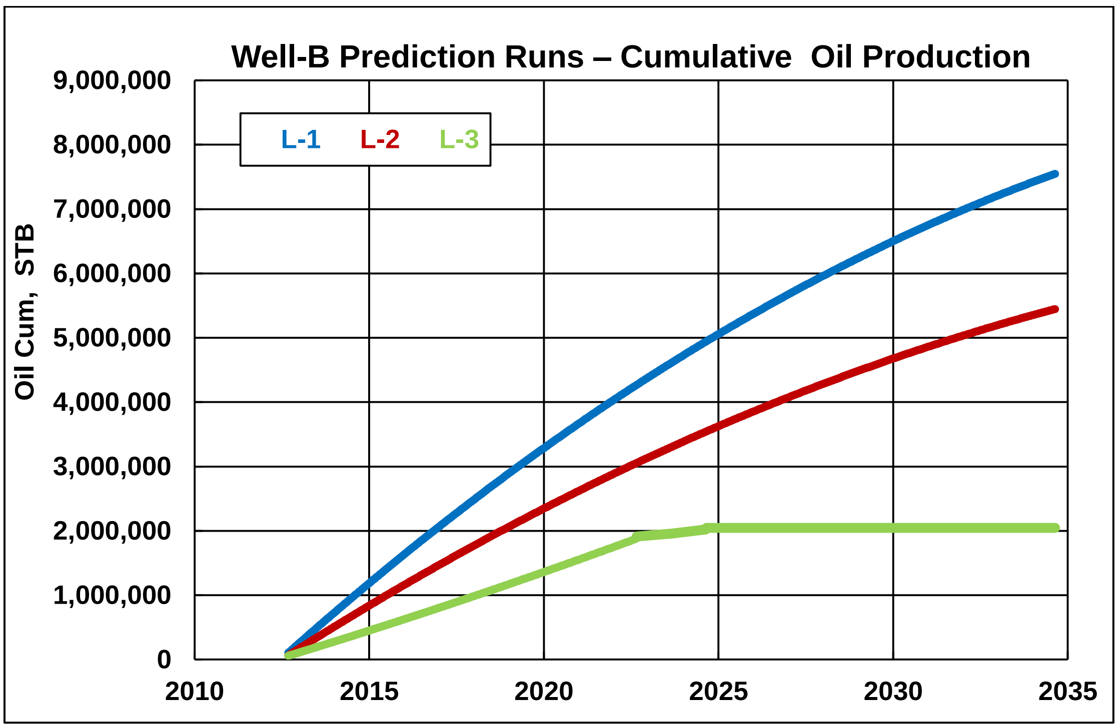

Figure 4.62: Well-B Prediction Runs – Cumulative Oil Production

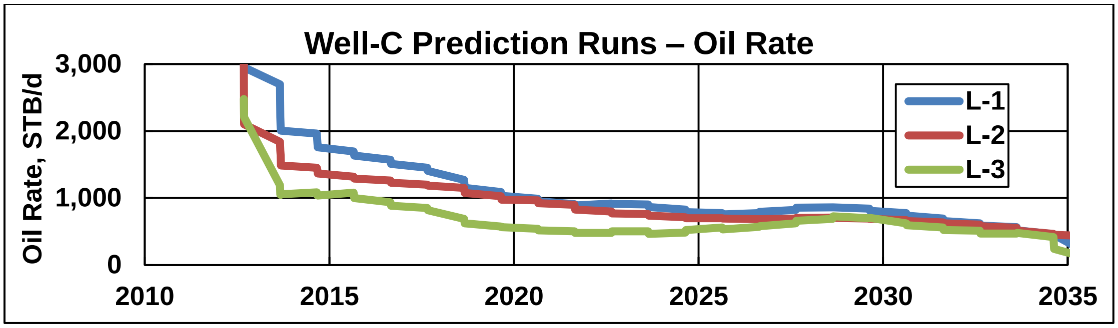

Figure 4.63: Well-C Prediction Runs – Oil Rate

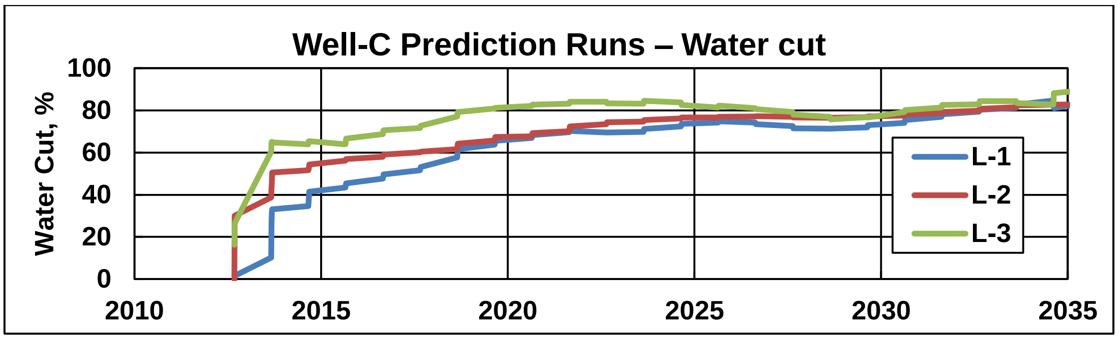

Figure 4.64: Well-C Prediction Runs – Water cut

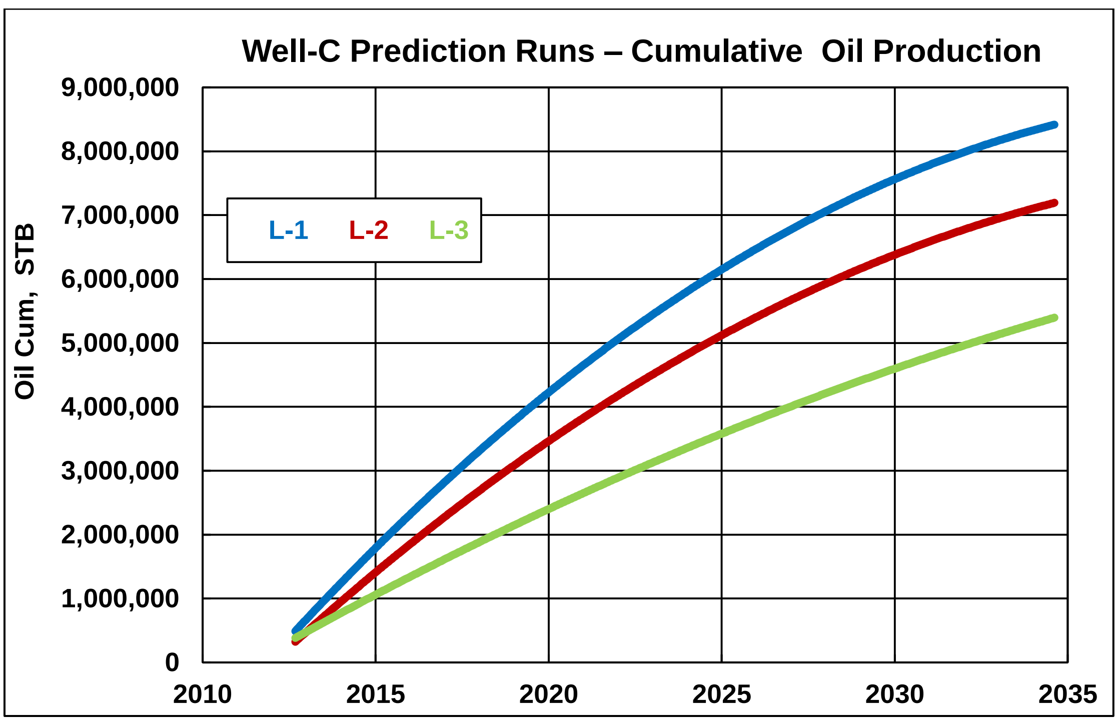

Figure 4.65: Well-C Prediction Runs – Cumulative Oil Production

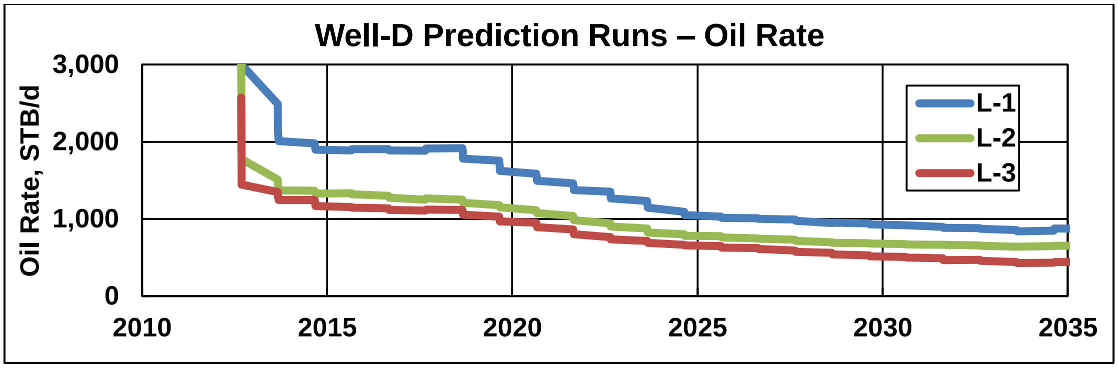

Figure 4.66: Well-D Prediction Runs – Oil Rate

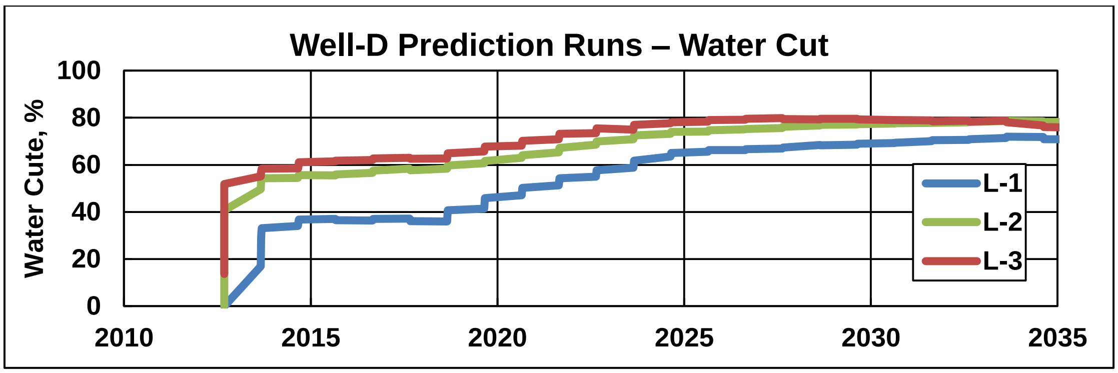

Figure 4.67: Well-D Prediction Runs – Water Cut

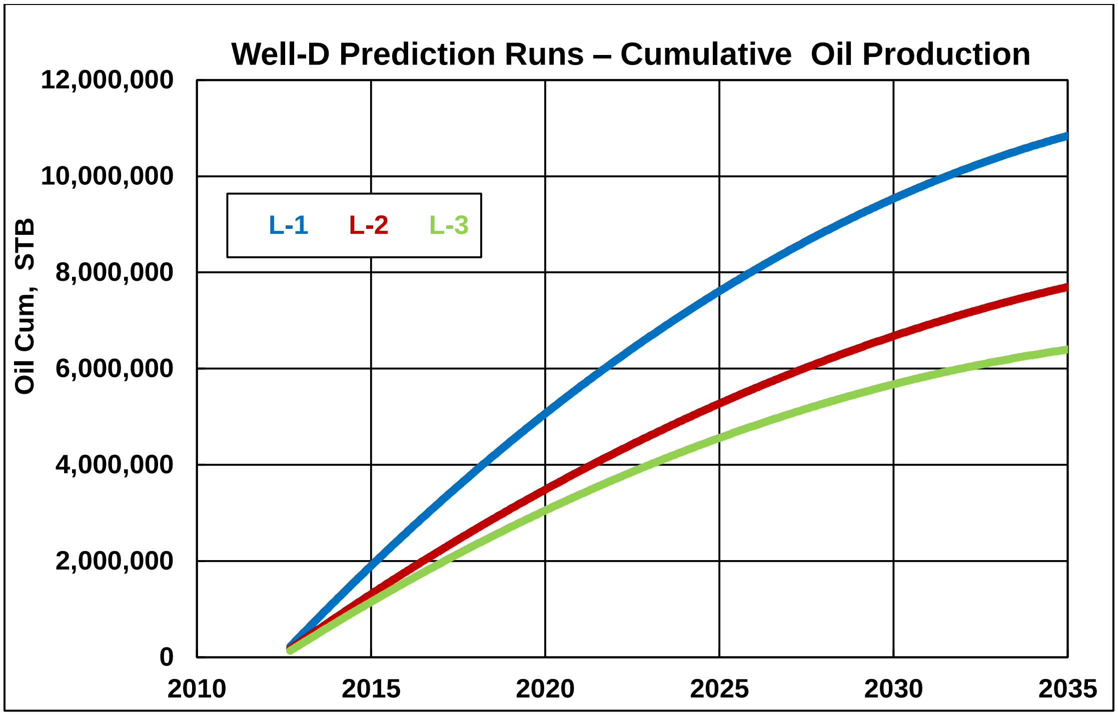

Figure 4.68: Well-D Prediction Runs – Cumulative Oil Production

4.4.2 Sensitivity Analysis of the Length of Reservoir Contact

Another set of prediction runs were performed to evaluate the impact of changing the length of the reservoir contact for each of the four selected wells. In these runs, all of the parameters were kept constant except the length of the reservoir contact which was varied at 2,000 ft, 4,000 ft, 6000 ft and 8,000 ft. The same constrains that were used in the previous set of prediction runs were used in this case. Placement was selected to be in the upper most layer of the targeted zone (L-1). Long term predictions of more than 30 years were utilized. Results were evaluated based on oil rate, water cut and more importantly cumulative oil production.

Results of the prediction runs for Wells-B, C and D were similar. Increasing the length of the horizontal section in these three wells from 4,000 ft to 6,000 ft resulted in significant improvement in well performance. This improvement was in terms of lower water cut and higher cumulative oil production. Increasing the length from 6.000 ft to 8,000 ft resulted in a very minor improvement in well performance once compared to the improvement resulted from increasing the length from 4,000 ft to 6,000 ft. Wells with length of 4,000 ft showed better performance when compared to the 2,000 ft of well length. On the other hand, the prediction runs for Well-A showed that the highest cumulative oil production and lowest water cut is achieved at a horizontal section length of 6,000 ft. Increasing the length to 8,000 ft resulted in a poor performance represented by the lowest cumulative oil production and the highest water cut, Figs-4.69-4.80.

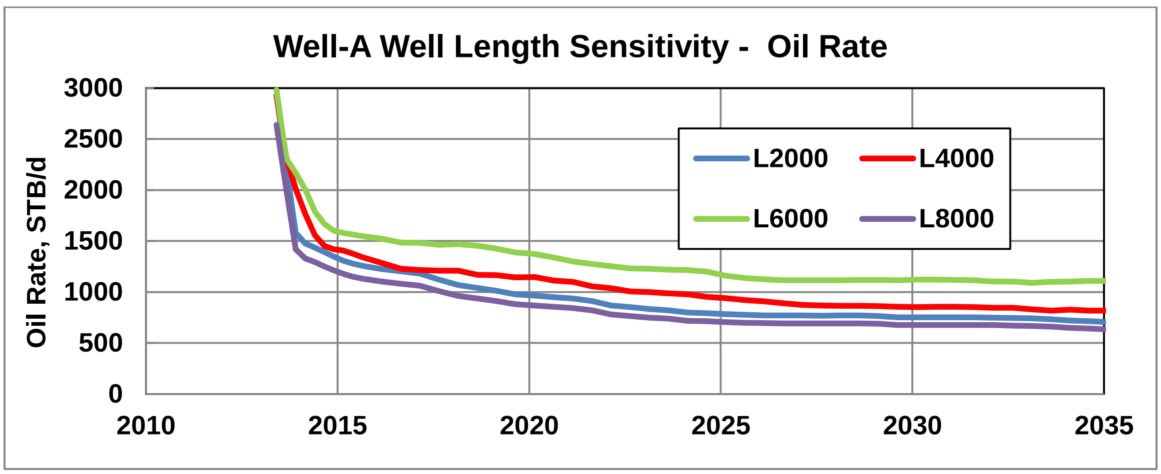

Figure 4.69: Well-A Well Length Sensitivity - Oil Rate

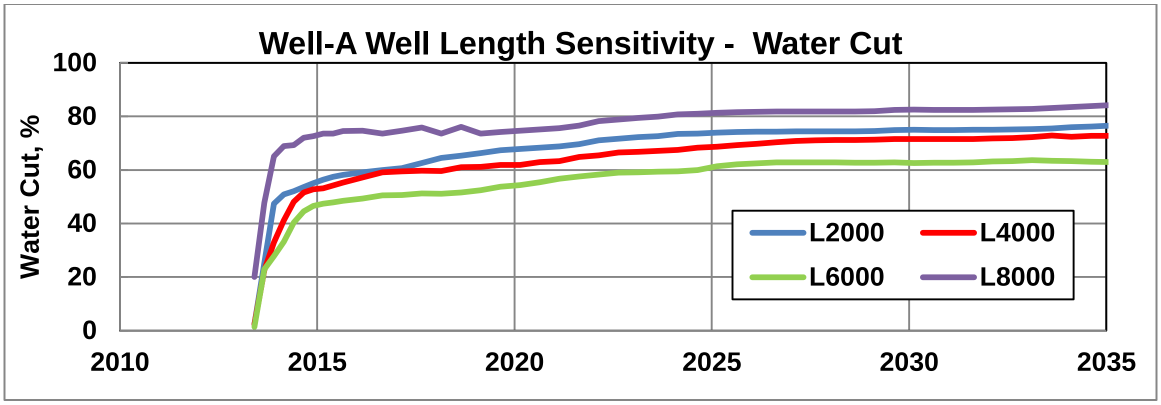

Figure 4.70: Well-A Well Length Sensitivity - Water Cut

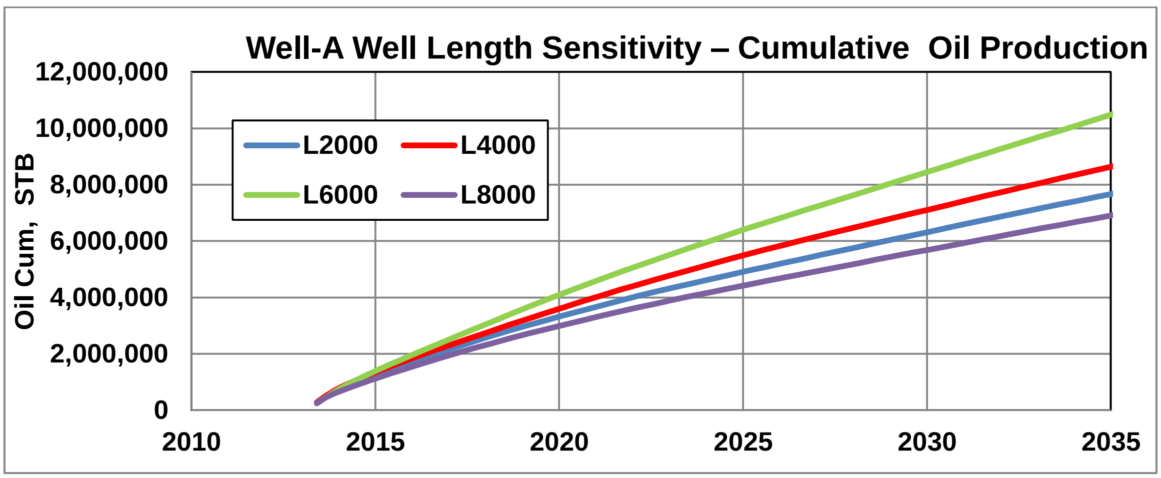

Figure 4.71: Well-A Well Length Sensitivity – Cumulative Oil Production

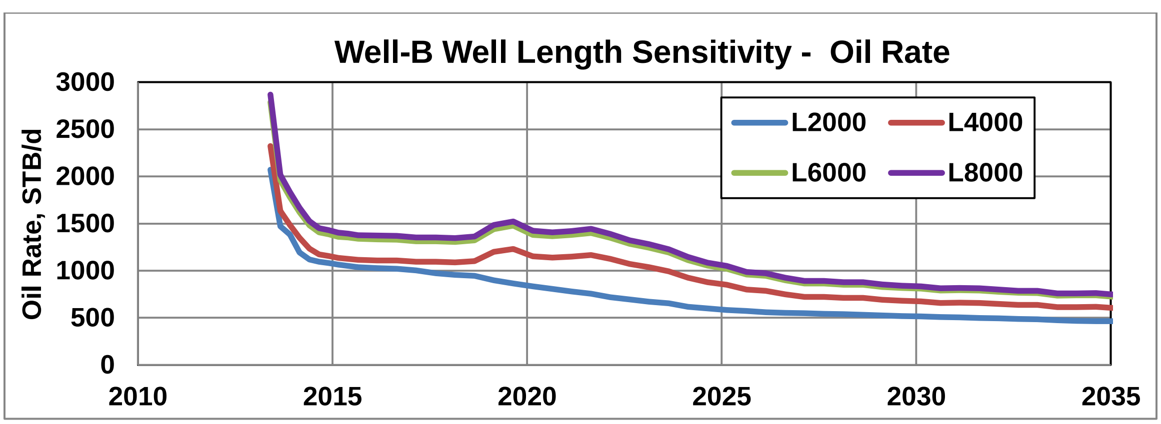

Figure 4.72: Well-B Well Length Sensitivity - Oil Rate

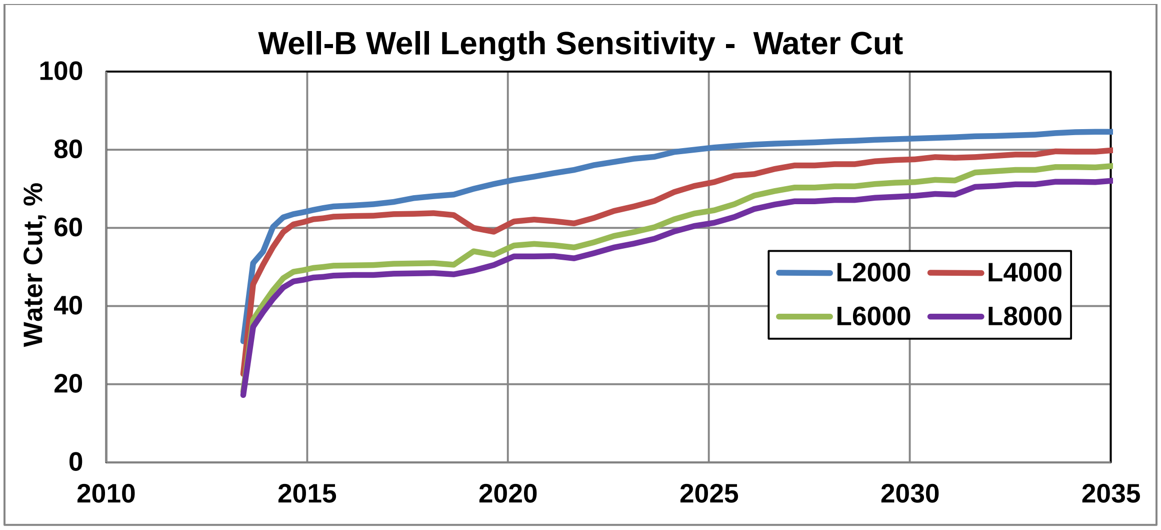

Figure 4.73: Well-B Well Length Sensitivity - Water Cut

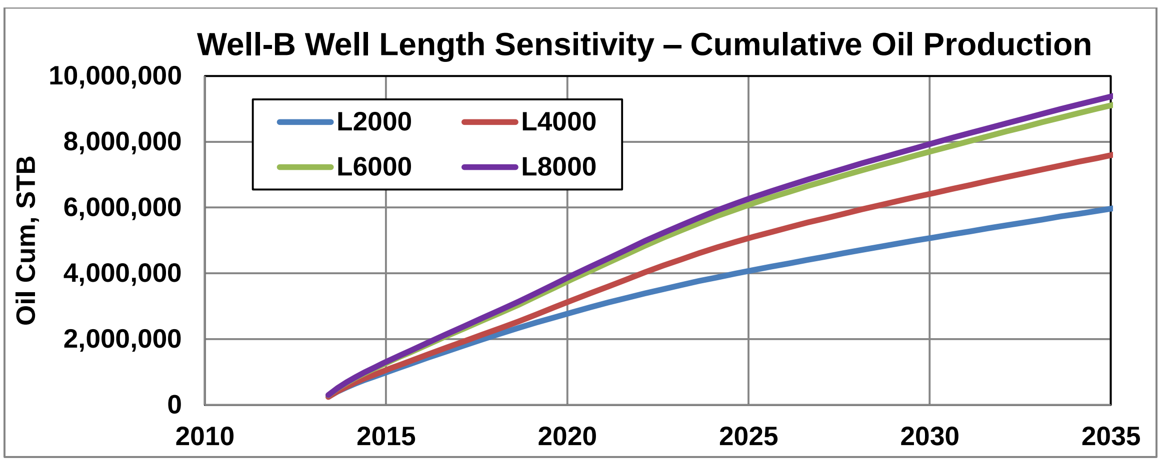

Figure 4.74: Well-B Well Length Sensitivity – Cumulative Oil Production

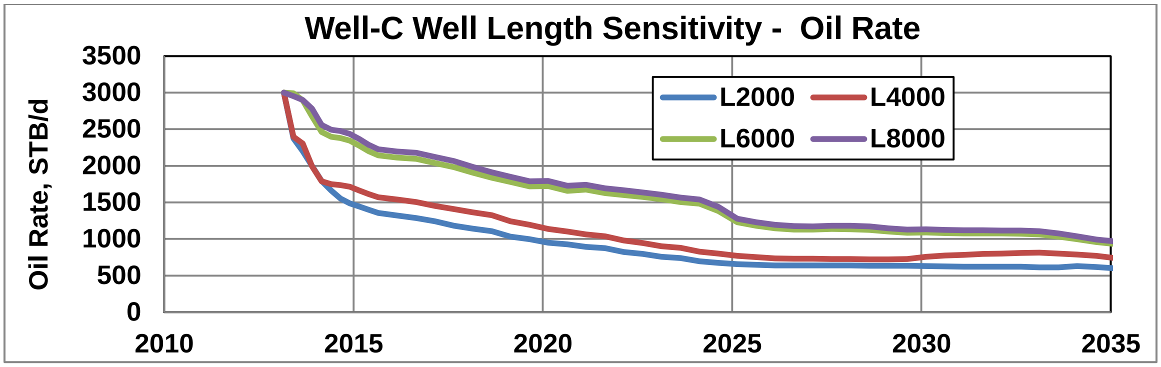

Figure 4.75: Well-C Well Length Sensitivity - Oil Rate

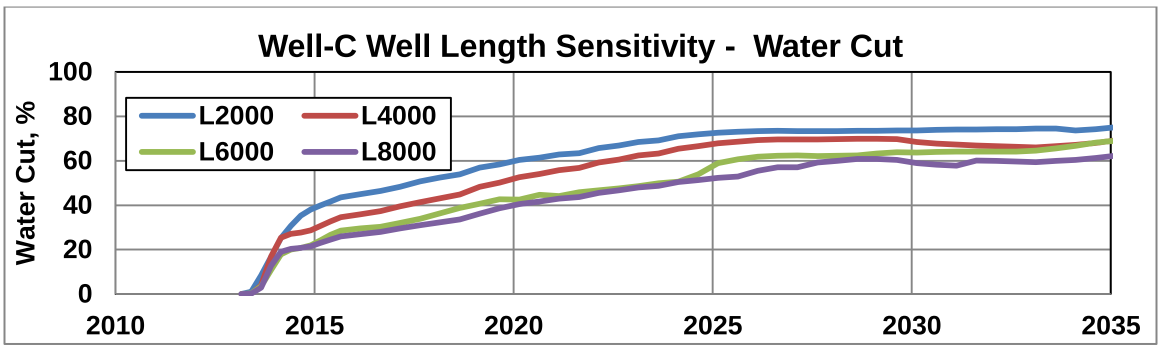

Figure 4.76: Well-C Well Length Sensitivity - Water Cut

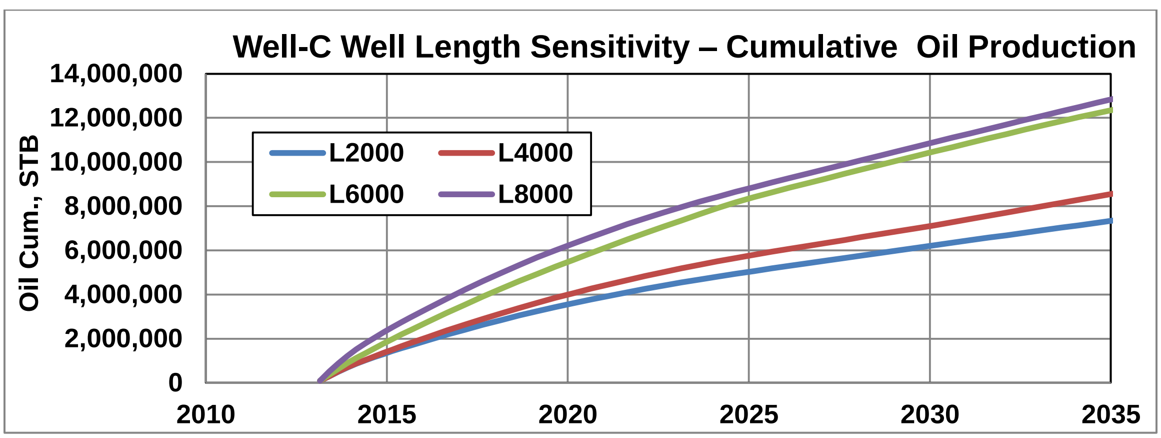

Figure 4.77: Well-C Well Length Sensitivity – Cumulative Oil Production

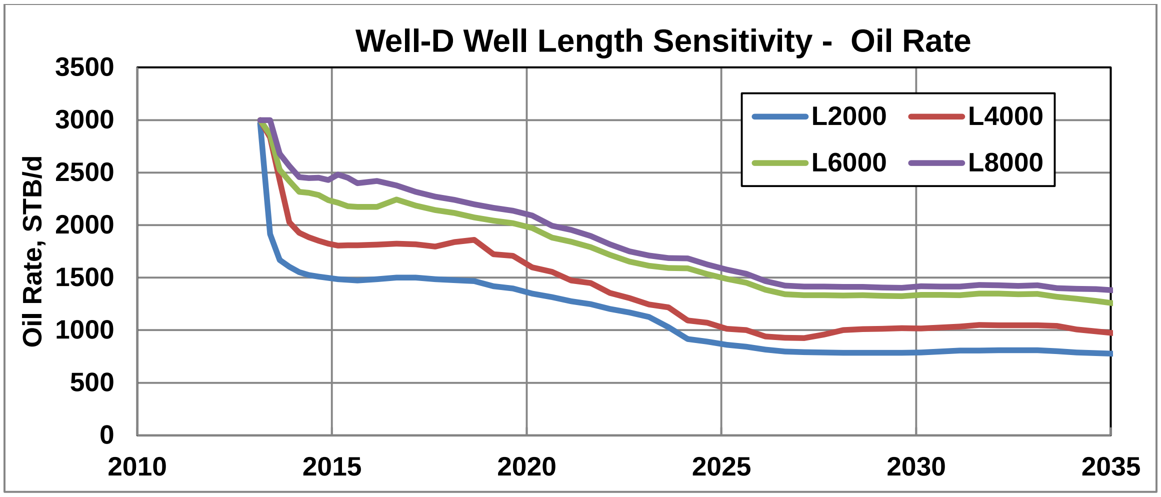

Figure 4.78: Well-D Well Length Sensitivity - Oil Rate

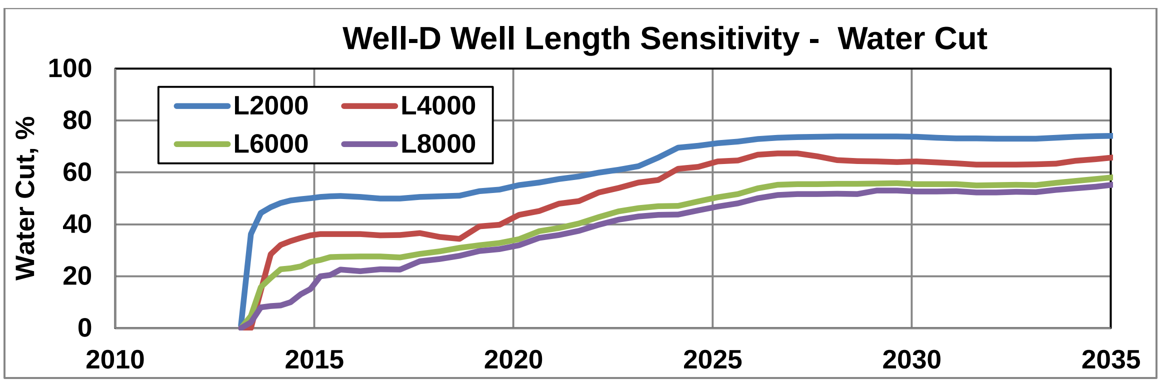

Figure 4.79: Well-D Well Length Sensitivity - Water Cut

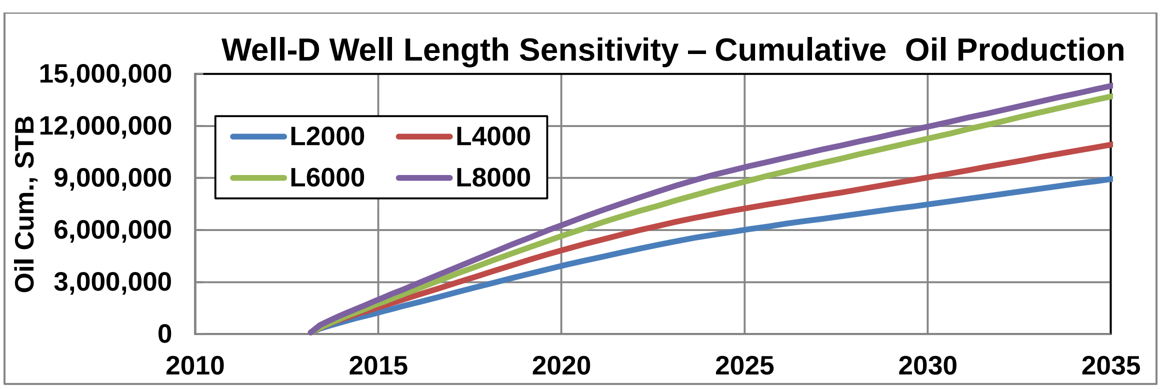

Figure 4.80: Well-D Well Length Sensitivity – Cumulative Oil Production

CHAPTER 5

RESULTS AND DISCUSSION

5.1 Discussion of the Results of the Vertical Placement Sensitivities

For the first candidate well, Well-A, predictions showed that 8.3 MMSTB of cumulative oil production could be achieved when the lateral is placed in the top layer (L-1). They also showed that the well will start producing at 7.3% WC which will increase to 77.5% by 2035. When placed in the middle layer (L-2), the well will be able to produce a lower amount of oil as it will able to produce 6.9 MMSTB. In this case it will start producing at 26.2% WC which will increase to 82.2% by 2035. When placed in the bottom layer (L-3), the cumulative oil production was even lower at 5.5 MMSTB. The well in this case will start producing at a higher water cut of 41.6% that will increase to 82.2% by 2035, Fig. 5.1.

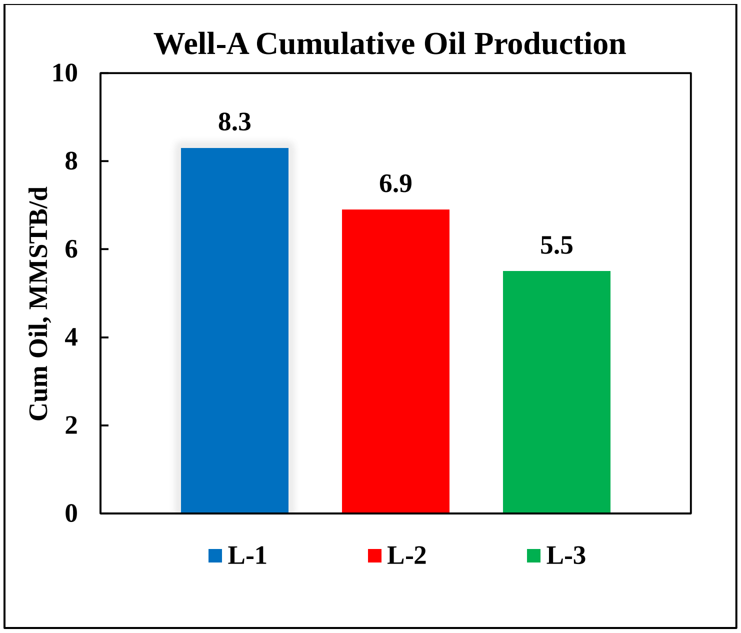

Figure 5.1: Well-A Cumulative Oil Production

For Well-B, 7.7 MMSTB of cumulative oil production can be achieved when the lateral was placed in the top layer (L-1). The well in this case will start producing at 22.6% WC which will increase to 79.5% by 2035. Placement in L-2 will yielded a 5.6 MMSTB of cumulative oil production at a water cut that will start at 47% and will increase up to 84.4% by 2035. Placement in L-3 resulted in a much lower cumulative oil production of only 2.0 MMSTB. Not only that, but also the model indicated that the well in this case will not be able to sustain flow to 2035 as it will die in 2024 after only 10 year of production due to excessive water production. The model showed that, when placed in the bottom layer (L-3), the well will start producing at high water cut of 79% which will increase to 83% by 2024 and causing the well not being able to flow, Fig. 5.2.

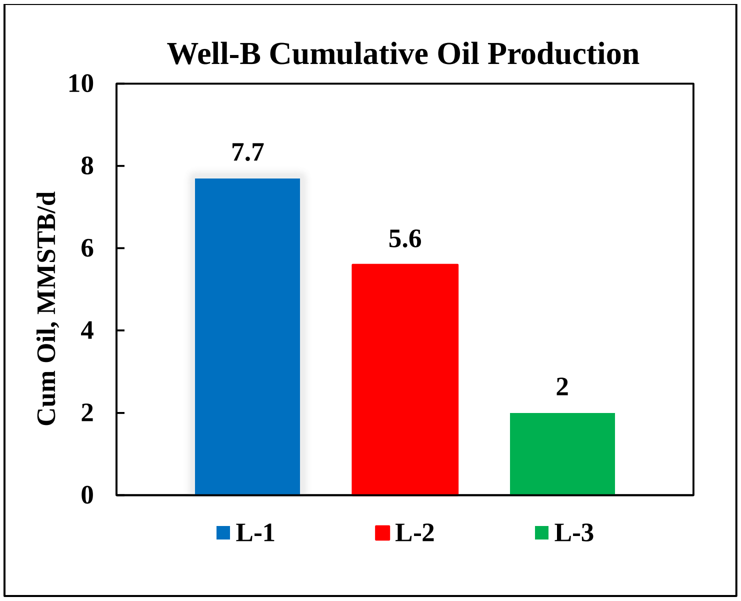

Figure 5.2: Well-B Cumulative Oil Production

The results of the 3rd candidate, Well-C, are similar. The highest cumulative oil production of 8.7 MMSTB was achieved by placing the lateral in L-1. The lateral placed in this layer will start producing dry oil but within a year, the water cut will increase to 10% and it will reach to 84% by 2035. A lower cumulative oil production 7.5 MMSTB was achieved by placing the lateral in L-2. When placed in L-2, will start producing at 0% WC which will increase to 30% within three months and to 83% by 2035. The lowest cumulative oil production of only 5.6 MMSTB was achieved when the lateral was placed in L-3. In this case, the well will start producing at a water cut of 16% that will increase up to 90% by 2035, Fig. 5.3.

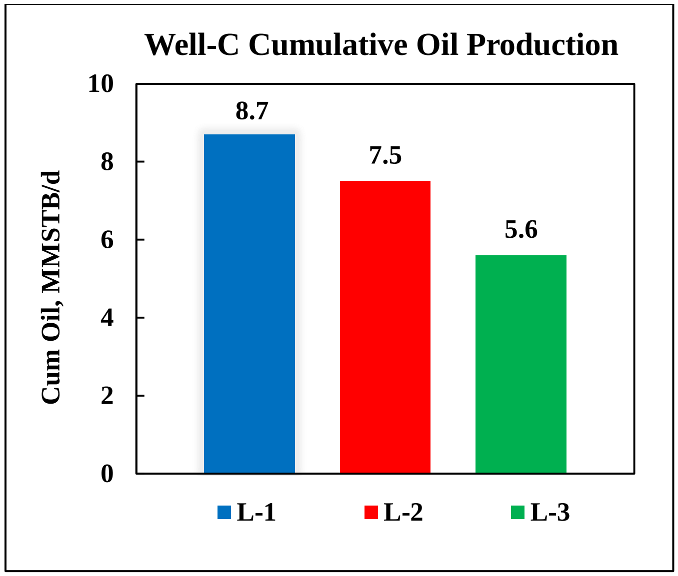

Figure 5.3: Well-C Cumulative Oil Production

The results of the 4th candidate, Well-D, are in agreement with the results of the previous three wells. Placement in the top layer (L-1) yielded the highest cumulative oil production of 11.1 MMSTB. The well in this case will start producing at 0% water cut that will increase to 17% within six months and will reach 71% by 2035. Placement in L-2 resulted in 1% water cut at the start production that will increase up to 75% by 2035. Cumulative oil production in this case was 7.9 MMSTB. Placement in L-3 yielded the lowest cumulative oil production of only 5.6 MMSTB where it will start producing at 13% water cut that will increase to 78% by 2035, Fig. 5.4.

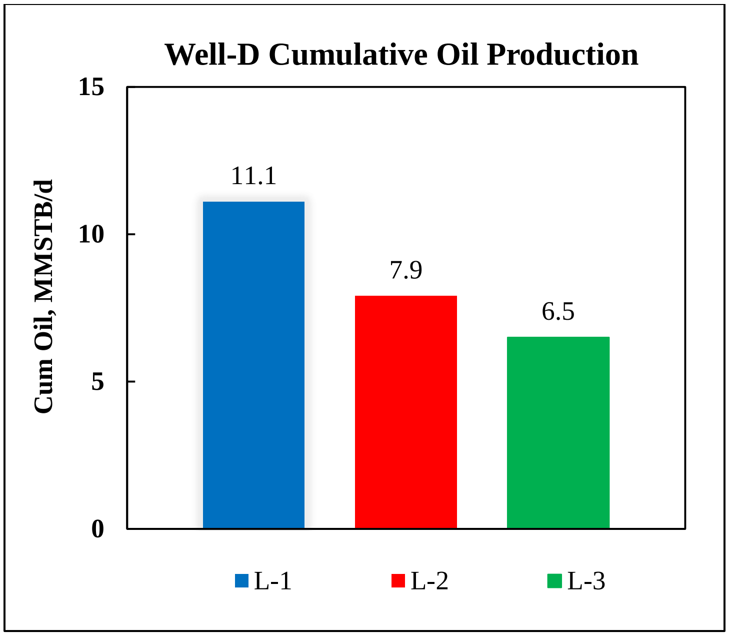

Figure 5.4: Well-D Cumulative Oil Production

In all of the four cases, side-tracking the wells with placement in the upper most zone, zone-1, will result in maximizing recovery as all of them will yield additional oil that can be produced. Side-tracking the wells will not only results in producing the un-depleted oil in zone-1, but will also help in recovering the oil that is at the top of the lower zone. The amount of this additional recovery varies and depends on the thickness of zone-1 as well as the thickness of the remaining oil column in the lower zone.

All cases demonstrated that the amount of cumulative oil is strongly impacted by the vertical placement of the laterals. Placement in the top layer resulted in the highest cumulative oil and the lowest water cut. Lower cumulative oil was produced if placed in the middle layer. Placing the wells in the bottom layer resulted in the lowest cumulative oil and the and highest water cut. Results were more pronounced in the case of Well-B. The lateral placed in this layer will not be able to sustain flow for more than 10 years.

The results can be explained by proximity of the layer in which the lateral is placed to the lower zones which are already largely depleted. When the wells are produced, pressure sinks are created. The closer the placement to lower zones, the faster water break-through and the higher water cut and since the lower zones have higher rock quality, the movement of water could be very rapid and thereby strongly impacting the performance of the wells. This results in wells not being able to sustain flow resulting in the oil in upper layers not being produced.

5.2 Discussion of the Results of Well Length Sensitivities

For the first well, Well-A, predictions showed that 10.72 MMSTB of cumulative oil production can be achieved when the lateral length is 6,000 ft. It also showed that the well in this case will start with dry production until reaching a water cut of 63% by 2035. In the case of 4,000 ft well length, the well was able to produce lower amount of oil as it will able to produce 8.82 MMSTB. In this case, it will start producing at 2% WC which will increase to 73% by 2035. When well length was 2,000 ft, the cumulative oil production was even lower at 7.83 MMSTB. The well in this case will start producing at a higher water cut of 3% that will increase to 77% by 2035. The lowest cumulative oil production of 7.04 MMSTB and the highest water cut is achieved with 8,000 ft. This is because when the length is 8,000 ft, the well will intersect with a major conductive natural fracture as mapped in the model. This fracture causes excessive water production since it cuts through and bring water from the lower zones which are already mainly swept. Fig. 5.5.

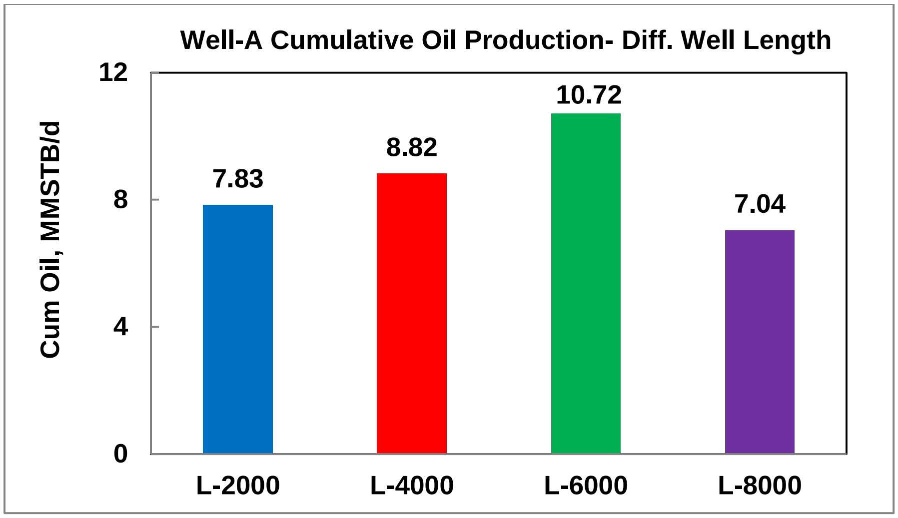

Figure 5.5: Well-A Cumulative Oil Production- Diff. Well Length

For Well-B, 9.27 MMSTB of cumulative oil production was achieved when the lateral length is 6,000 ft. This is significantly higher than the cumulative production achieved with 4,000 ft of 7.72 MMSTB by 18%. The well in this case will start producing at 18% WC which will increase to 76% by 2035. A cumulative oil production of 9.55 which is higher than the cumulative oil production achieved with the 6,000 ft by only 3% can be achieved when the lateral length was 8,000 ft. Placement of 4,000 ft of reservoir contact will yielded a 7.72 MMSTB of cumulative oil production at a water cut that will start at 22% and will increase up to 80% by 2035. Placement of 2,000 ft of reservoir resulted in a lower cumulative oil production of only 6.07 MMSTB. The model showed that the placement of 2,000 ft resulted in the well to start producing at high water cut of 31% which will increase to 85% by 2035, Fig. 5.6.

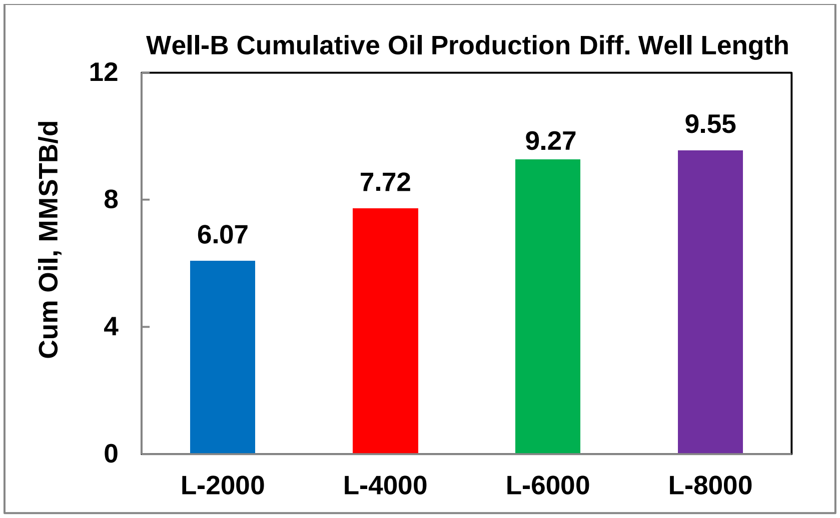

Figure 5.6: Well-B Cumulative Oil Production Diff. Well Length

The results of Well-C, are similar to the results of Well-B. Cumulative oil production of 12.56 MMSTB was achieved at a well length of 6,000 ft. This is higher than the cumulative oil production achieved with 4,000 ft by 30% and less than the cumulative oil production achieved with 8,000 ft which is 13.07 MMSTB by only 4 %. With the length of 6,000 ft, the water cut will increase to 18% within the first year and it will reach to 70% by 2035. A lower cumulative oil production of 8.70 MMSTB was achieved with 4,000 ft well length. In this case, the well will start producing at 0% WC which will increase to 25% within three months and to 71% by 2035. The lowest cumulative oil production of only 7.48 MMSTB was achieved when the reservoir contact is 2,000 ft where the well will start producing at a water cut of 0% that will increase up to 76% by 2035, Fig. 5.7.

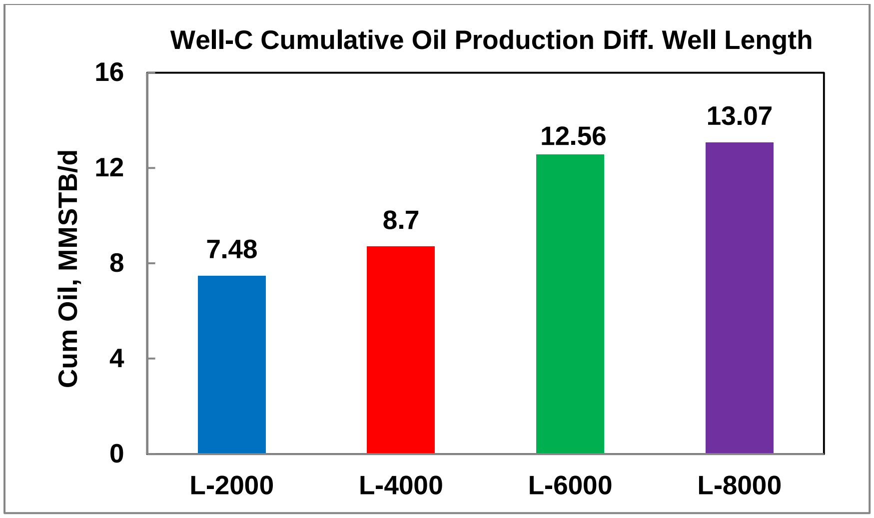

Figure 5.7: Well-C Cumulative Oil Production Diff. Well Length

The results of the 4th candidate, Well-D, are in agreement with the results of Well-B and C. Placement of 6,000 ft of reservoir contact yielded cumulative oil production of 13.99 MMSTB. This is higher than the cumulative oil production of the 4,000 ft well by 20% and less the 8,000 ft well by only 4%. The well in this case will start producing at 0% water cut that will increase to 16% within six months and will reach 59% by 2035. Placement of 4,000 ft resulted in the starting to produce at 1% water cut that will increase up to 66% by 2035 and will yield 11.13 MMSTB of cumulative oil production. Placement of 2,000 ft yielded the lowest cumulative oil production of only 9.12 MMSTB where it will start producing at 1% water cut that will increase to 74% by 2035, Fig. 5.8.

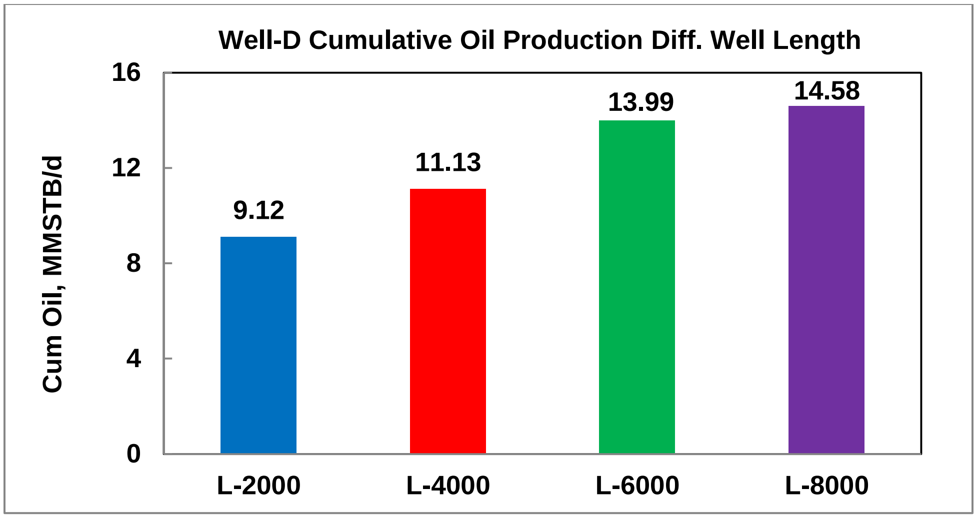

Figure 5.8: Well-D Cumulative Oil Production Diff. Well Length

The relationship between well performance and the length reservoir contact can be explained by the fact that, in general, longer wells have higher productivity index (PI). Higher well PI provides ability to produce the required well rate at a lower pressure drop when compared to a shorter well. Lower pressure drop results in reducing water coning and thereby reducing water production, increasing oil production and prolonging well life. However, other factors also affect the well performance. An example is natural fractures as seen in Well-A. The minor increase in cumulative oil production by increasing the length of well-B, C and D from 6,000 ft to 8,000 ft is due to lower rock quality For last 2,000 ft where the laterals were placed.

CHAPTER 6

CONCLUSIONS

Historical production through vertical wells has left the thin, upper most zone largely un-depleted due to the large rock quality contract with the underlying, thick, productive zones. In addition, zone-1 has particularly complex reservoir geology with higher degree of heterogeneity when compared to the lower zones. This has been found through the strategic monitoring program implemented in the field.

Zone-1 remaining un-swept created an opportunity to obtain direct production from this zone through dedicated producers. Since it has been well established that horizontal wells are superior mean of developing challenging reservoirs, the feasibility of exploiting this zone through horizontal wells was assessed. The development of this zone relied mainly on side-tracking existing marginal wells aiming at maximizing the utilization of existing assets while minimizing unit development cost.

The selection of the potential Side-tracking candidates was done through reviewing engineering data as well as the geological and simulation model. The full-field simulation model was utilized in order to assess the optimum vertical placement of four horizontal wells to effectively produce this zone. Prior to carrying out the prediction runs, the history matching of the model was reviewed. Historical performance of the selected wells and their off-sets was reproduced. Prediction runs were performed to assess the impact of the vertical placement and the length of the reservoir contact on well performance. The model showed that the placing horizontal wells in this zone results in a significant added recovery. The model also clearly showed that the vertical placement of these horizontal wells plays a major role in their performance. All cases demonstrated that the amount of cumulative oil is strongly impacted by the vertical placement of the laterals. Placement in the top layer results in the highest cumulative oil, the lowest water cut and longer well life. Lower cumulative oil will be produced if placed in the middle layer. Placing the wells in the bottom layer results in the lowest cumulative oil and the and highest water cut.

Moreover, the model showed that, in general, the longer the reservoir contact, the better well performance. Higher cumulative oil production and lower water cut could be achieved by extending the well length. In addition, the model showed that intersecting natural fractures has a negative impact on well performance due to the excessive water production. Furthermore, extending the length of the reservoir contact to areas with low rock quality adds only minor additional cumulative oil production.

Therefore, it is recommended for similar types of reservoirs and based on this work to place wells at the upper most layer of the reservoir provided that it has reasonable rock quality. In addition, well length should be maximized while considering avoiding intersecting natural fractures, avoiding placing the well in low rock quality and accounting for partiality and potentially operational issues.

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